BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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HEATHER L. ROSENTRATER

REPRESENTING AVISTA CORPORATION

Avista Utilities

Electric Transmission Infrastructure Plan

April 2018

Avista Asset Management Group

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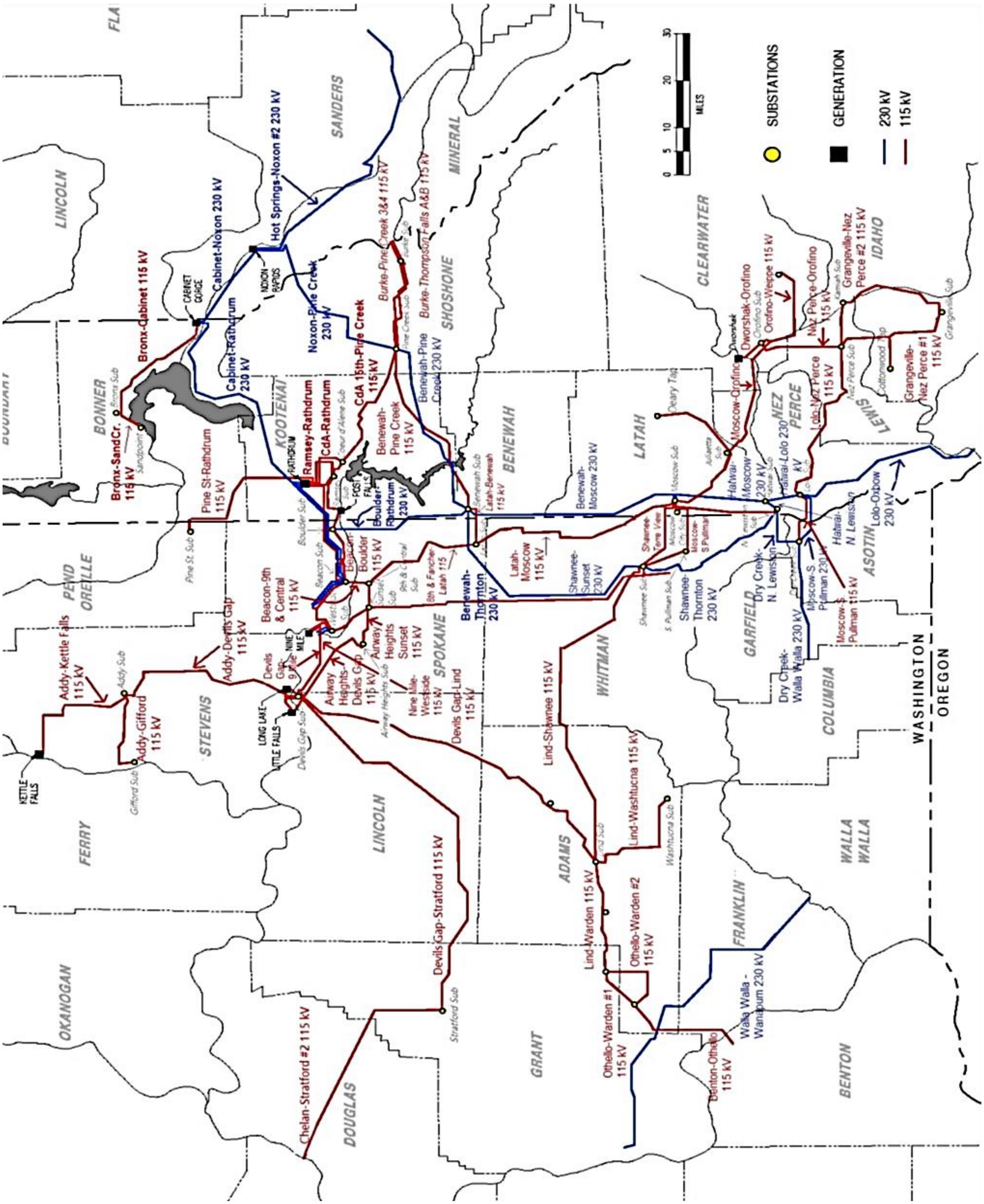


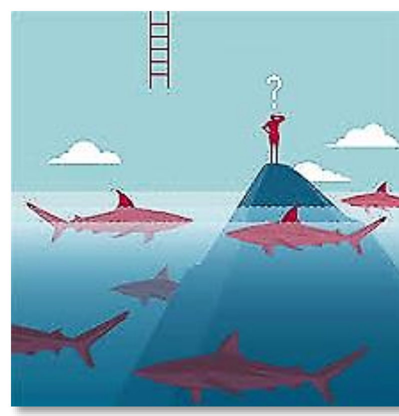
Executive Summary

Avista Utilities serves approximately 370,000 electric customers in Washington and Idaho over an extensive electric transmission system that is designed, built, operated and maintained by the Company. This infrastructure system consists of approximately 2,200 miles of high voltage transmission lines crossing 30,000 square miles and bringing electric power to over 1.6 million people in Washington and Northern Idaho. Avista must continually make new investments in this system in order to continue providing our customers with safe and reliable electric service, at a reasonable cost, with service levels that meet our customer's expectations for quality and satisfaction, and that meet stringent national, regional, state, and local regulatory requirements.

The purpose of this report is to provide a comprehensive overview of Avista's transmission system and associated programs, as well describe the need for capital investment, operations, and maintenance funding for our transmission system. But more importantly, the goal is to explain the many forces that are driving these needs. We believe this visibility provides meaningful context for better understanding these many demands and how Avista is attempting to balance complex and competing needs.

Electric Transmission at the Crossroads

Our nation's electric utilities are facing times of unprecedented challenge when it comes to the forces driving the need for new investment in our transmission infrastructure, and Avista is no different. This growing demand for new investment has overwhelmed our ability to fund all of our high-priority needs for electric transmission, which are out of proportion to the investment requirements of our other infrastructure. Drivers for new investment include:



- Capital funding needed for system improvements to meet the myriad and expanding federal regulations governing nearly every aspect of our transmission business. Priority among these, as of late, are the requirements to meet more restrictive transmission operations and planning standards, both of which drive the need for new investment. These requirements are accompanied by the threat of financial penalties for noncompliance.
- Timely replacement of end-of-life assets. This need is at an all-time high across the industry, and it will continue to increase year-over-year for at least the next two decades. This need is the result of the dramatic increase in construction of new electric infrastructure during the economic boom that followed the end of World War II. Because these assets are now at or near the end of their useful lives, a substantial boost in new investment is required compared with previous years just to properly maintain existing systems.
- Shifts in the loads served by our transmission system, including transmission interconnections to private parties for such needs as the integration of new variable energy resources,

particularly wind and solar. These interconnections require significant capital investment to extend or reinforce our transmission system in order to provide for these non-traditional uses of our system.

- The role required to support development of the new energy services grid of the future. Though primarily focused at the distribution level, these changes in our energy delivery business model are expected to impact the investments we make in transmission and create uncertainty about future cost recovery for them.
- Siting, permitting and constructing transmission assets has become more complex, time-consuming and expensive due in part to increasing environmental and property requirements. Landowners, public and private, seek more compensation for rights-of-way and access agreements than in the past. Local, state, and federal permitting requirements cover issues such as endangered species, historical and cultural resources, water quality, wildlife and more. Permitting can extend over several years and typically includes conditions that constrain how utilities construct or maintain these assets as well as requirements for site restoration.
- New technology is driving change and new ways of engaging with customers. The grid is facing increasing digitization, distributed generation, energy storage, and other technologies that require adapting and upgrading the existing system. Customers are requiring new services, increased levels of reliability, flexibility, and choice that are beyond the experience of traditional power companies. These demands not only create uncertainty, but add cost.

When it comes to the impact for our customers, who must ultimately pay for these requirements and investments, an exacerbating factor is our relatively stagnant load growth due to declining use per customer. This translates into nearly flat revenues, which means that new capital investments must be covered by higher customer rates. Historically, annual increases in customer loads produced new revenues that were often sufficient to cover the costs for new investment and inflation without the need to increase customer rates.

This report intends to demonstrate the way Avista is responding to the challenges facing the industry. In order to do this most effectively, the Company has developed strategies and methodologies to meet competing financial needs through formalized decision-making processes as described below.

Avista Investment Selection Process

Engineering Roundtable

How do Avista's Transmission Planning, System Operations and Engineering business units evaluate and prioritize proposed transmission projects? Several steps are involved in determining which projects should be considered for funding.

Upgrading Sunset Substation

Initially, projects are developed through planning studies, engineering and asset management analyses, and scheduled upgrades or replacements identified in the operations districts and within engineering groups. These projects undergo internal review by multiple stakeholders who help ensure all system needs and alternatives have been identified and addressed. If proposed projects are initially approved, they go through a formal review process referred to as the "Engineering Roundtable." The purpose of the Engineering Roundtable (ERT) is to provide an actionable roadmap that identifies and prioritizes projects that will benefit Avista and our customers. Each proposed project includes clear justification and alternatives analysis to achieve positive regulatory outcomes. The ERT seeks to enhance efficiency and effectiveness of capital spending and resource allocation while acknowledging and validating internal customer needs and providing clear communication, visibility, and transparency as decisions are made.

Business Units Represented in the Engineering Roundtable

- *Transmission Planning*
- *Distribution Planning*
- *Transmission Design*
- *Substation Design*
- *System Protection*
- *Distribution Design*
- *System Operations*
- *Asset Management*
- *Communications Engineering*
- *Transmission Services*
- *Generation Engineering*


North-South Freeway Relocation

The Engineering Roundtable serves as a communication and review committee for projects requiring Transmission, Substation, or Protection engineering support. The Committee is responsible to track project requests, prioritize them, and establish committed construction package dates and required in-service dates for projects that are consistent with the Company's vision and corporate strategies. Representatives from eleven business units participate in the ERT process.


Dry Creek 230/115 transmission auto transformer making its way to Dry Creek Substation

Each business unit proposing a project is required to fill out a form explaining the problem, the primary business driver, alternatives considered, and the justification for the approach recommended. During the review, the potential benefits of any cross-business unit synergies that could better optimize project benefits and scope are also identified and evaluated. The primary output of this process is a list that serves as a roadmap of projects that are scoped at a high level and sequenced by year for at least a ten-year time horizon. It is then communicated across the organization so that each department can plan ahead for the work that they will be responsible to execute. Once a project has passed this phase of evaluation, it moves to the Capital Planning Group for final review.

Capital Planning Group

The Engineering Roundtable creates a prioritized list of needed investments for electric transmission. Business cases are completed for the projects on this list and submitted to the Capital Planning Group (CPG), a group of Avista Directors that represent capital intensive areas of the Company. Committee members are directors from a variety of business units to add a depth of perspective, though their role is to consider capital decisions from the perspective of *overall* Company operations and strategic goals. The CPG reviews the submitted Business Cases from various departments and prioritizes funding to meet the upcoming five year capital spending guidance set by senior management and approved by the Finance Committee of the Board of Directors. The CPG meets monthly to review the status of the capital projects and programs, evaluate changes requested, and approve or decline new Business Cases. They also monitor the overall current year capital budget. This group develops and recommends a 5-year capital expenditure plan by investment driver to the Company's officers. The CPG is responsible for reviewing, approving, deferring, or denying capital requests, and for appraising productivity and strategic proposals.

Initial expenditure requests may need to be modified based on the timing of equipment, permits, available crews, priorities of projects, etc. The CPG approves or declines these changes based on managing a total budget amount. Therefore, as changes occur throughout the project, project funding may change, or one project may be funded while another is removed or delayed to allow higher priority projects to be funded. This is done while remaining within the total approved capital spending amount. This group reprioritizes as needed to ensure that the highest priority projects are identified and funded.

Hot Springs – Noxon #2: Replacing old wood structures with steel

Avista's Capital Planning Group evaluates aspects such as the project description, alternatives, cost and other financial assessments, risk, justification, resource requirements, and how the project fits into the Company's overall strategies. They provide a comprehensive and strategic perspective that helps ensure that the right projects are funded adequately at the right time.

Ultimately the individual investments selected to be included in Avista's Transmission Infrastructure Plan represent a portfolio of projects and funding levels intended to optimize:

1) *The overall demand for transmission investment,*
2) *The specific requirements of the projects and programs proposed for funding, and the potential consequences associated with deferring needed investments, and*
3) *A balance among the needs and priorities of all investment requests across the enterprise and the Company's investment planning principles.*[1]

The result demonstrates a reasonable balance among competing needs required to maintain the performance of Avista's systems, as well as prudent management of the overall enterprise in the best interest of customers.

External factors such as new regulatory or legislative requirements may drive changes in the plan. The projects in the Company's portfolio are continuously reviewed for changes in assumptions, constraints, project delays, accelerations, weather impacts, outage coordination, system operations, performance, permitting/licensing/agency approvals, safety, and customer-driven needs that arise. The portfolio will be continually updated throughout the year to remain as accurate as possible.

Avista's Transmission Investments

Increasing Capital Investments for Infrastructure Needs

In recent years, Avista has experienced an increasing demand for new and upgraded infrastructure investment. The pattern of investments made by the Company during this period bear a resemblance to that of the industry, though Avista's investments have increased at a slower pace, as shown by the trend line in Figure 1 (with exceptions in the mid-2000s as will be discussed later in this report). This similarity should not be a surprise since we are all responding to the same investment drivers: the demand to replace an increasing amount of infrastructure that has reached the end of its useful life, ever increasing regulatory compliance

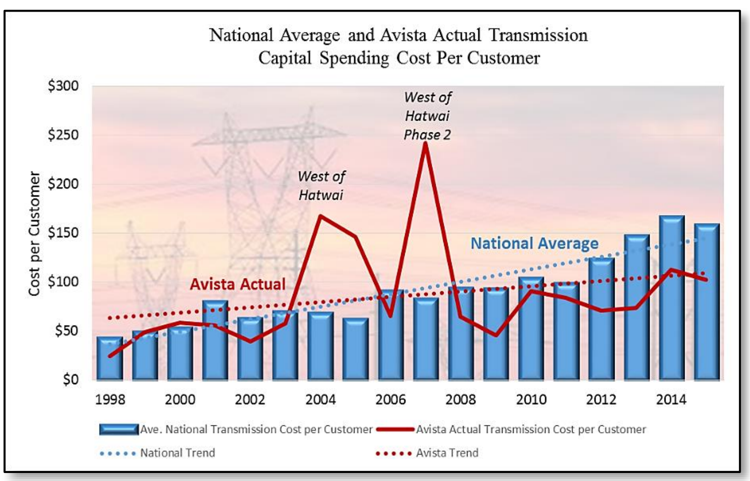


Figure 1. Infrastructure Investment Demands
Source of National Data: FERC Form 1[2]

[1] In setting its overall infrastructure spending limits, the Company considers a range of factors referred as "key planning principles" as shown in the bubble diagram.
[2] Note that compiled FERC Form 1 data is currently only available through 2015 – they are typically a year or two behind in providing this data to the public. https://openei.org/datasets/dataset/ferc-form-1-electric-utility-cost-energy-sales-peak-demand-and-customer-count-data-1994-2015

requirements, and the need for reliability and technology investments necessary to build the integrated energy services grid of the future. Avista's investments in electric transmission also reflect the Company's adoption of new asset management-based approaches for assessing infrastructure needs and developing strategies and programs to optimize the lifecycle value of our system.

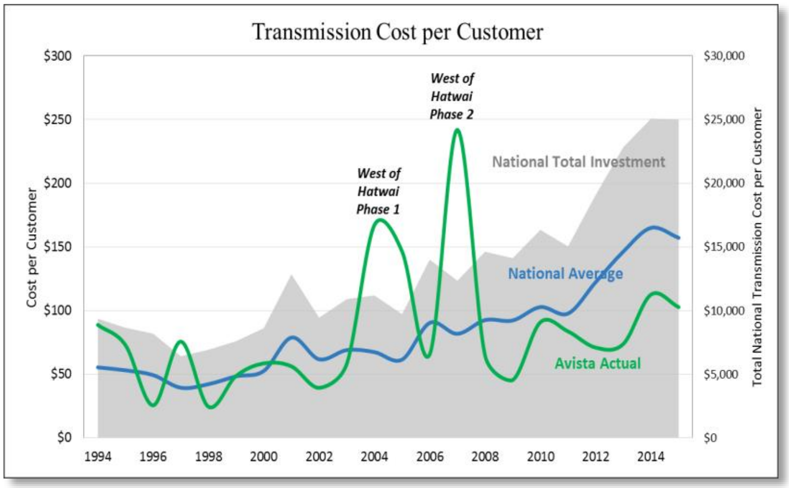


Figure 2. National & Avista Transmission Cost Per Customer
Source of National Data: FERC Form 1[3]

In the early 2000s, Avista was required to execute major upgrades in the transmission system to replace lines built in the 1950s and to mitigate congestion issues in the Northwest (as described in detail beginning on page 31) which pushed spending above the national average for that time period. Since the completion of those projects, our annual capital costs expressed on a per-customer basis are generally in line with, though below, that of the national electric utility industry, as shown in Figure 2. When considering the Company's Transmission, Distribution, and Generation infrastructure investments measured across the entirety of our business, Avista's historical capital cost per customer has varied, sometimes substantially, based on the intensity of our historic levels of investment and the number of customers we served at the time. However, the Company's spending tends to be very much in line with that of other utilities across the nation.

Classification of Infrastructure Need by Investment Drivers

As a way to create more clarity around the particular needs being addressed with each *capital* investment as well as simplifying the organization and understanding of our overall project plans, the Company has organized the infrastructure investments described in this report by the classification of need or "Investment Driver."[4]

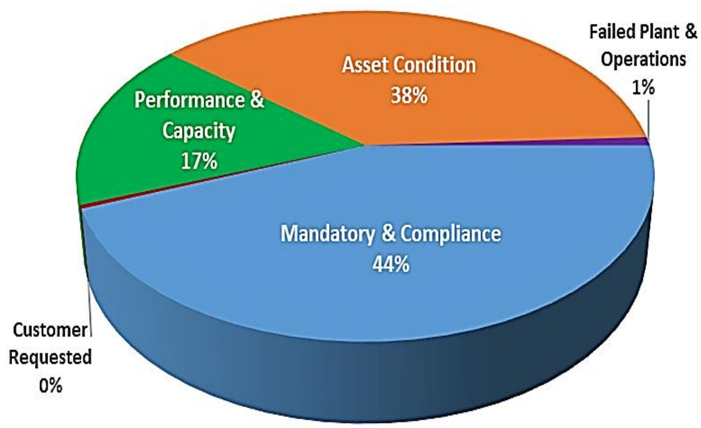


Figure 3. Total Planned Capital Expenditures by Investment Driver[5]

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[3] Note that compiled FERC Form 1 data is currently only available through 2015 – they are typically a year or two behind in providing this data to the public. https://openei.org/datasets/dataset/ferc-form-1-electric-utility-cost-energy-sales-peak-demand-and-customer-count-data-1994-2015

[4] Avista's Distribution asset class has a sixth investment driver, Customer Service Quality & Reliability. This driver is not applicable to the Transmission system, as Transmission does not typically directly impact customers. It is also planned and operated to maintain continuity of service to customers at all times, including during forced outage contingencies.

[5] The Failed Plant & Operations budget is split between Distribution & Transmission. This chart reflects 18.71% of the total, as that has been the percentage of the budget actually used by Transmission over the past five years.

The need for investments associated with each investment driver is briefly defined below, and in greater detail later in this report. Details about the projects in each category can be found in Appendix A, beginning on page 58.

1. ***Customer Requested*** – This category is primarily related to connecting new facilities for large transmission-direct customers or to enhance their service as requested. This category was used, for example, to provide for expenses related to the requested interconnection of Avista's new solar project, which is owned by an independent solar developer that requested interconnection.
2. **Customer Service Quality & Reliability** – This category is for expenses related to meeting our customers' expectations for quality of service and electric system reliability. Transmission does not have any dollars set aside under this category, as it does not typically directly impact customers – very few of our customers receive direct transmission service.
3. ***Mandatory & Compliance*** – The Company makes a large number of business decisions as a direct result of compliance with laws, mandatory standards, safety codes, contracts, and agreements. Examples include transmission reinforcement projects or control equipment required by NERC to preserve the reliability of the interconnected grid. These decisions are primarily driven by external requirements that are largely beyond the Company's control.

4. ***Performance & Capacity*** – Programs in this category ensure that our assets satisfy business needs and meet performance standards, typically defined by Company experts or in line with industry standards. Some examples include adding new substations or transmission lines to meet customer growth or to provide redundancy to reduce the potential for outages.

5. ***Asset Condition*** – All assets have a defined useful service life. This category provides funding to replace equipment as needed so it can continue to function effectively. It may include replacing parts as they wear out or when items can no longer meet their required purpose, as systems become obsolete and replacement parts are no longer available, to remedy safety or environmental issues, or if the condition of an asset is such that it is no longer optimizing its own performance or customer value. The Company also replaces critical equipment to mitigate the risk of failure.
6. ***Failed Plant & Operations*** – This category sets aside funds to replace failed equipment and support ongoing utility operations. Often these expenditures are the result of storm damage.

Transmission work at Noxon

All of Avista's capital expenditures are categorized into one of these Drivers, though not all of the investment driver categories are represented for each asset class. For example, electric distribution investments encompass all six categories; however, investments planned for electric transmission during the upcoming five year planning cycle do not include any projects in the category of Customer Service Quality and Reliability. This is fairly common, since very few of our customers receive direct transmission service. In addition, investments in electric transmission related directly to service reliability for all customers are generally driven by mandatory compliance requirements so can be found in the "Mandatory & Compliance" Driver. Note that not all of the investment drivers will be used in all of Avista's primary asset categories in every budgeting cycle, yet they remain an efficient and effective way of categorizing expenditures in a clear and transparent fashion that promotes better understanding of how the Company makes business decisions.

Overview of Currently Planned Investments in Electric Transmission 2018 – 2022

Planned Capital Investments

Over the current five-year planning horizon, Avista expects to spend approximately $364 million for transmission capital investments. The planned annual investments for this period ranges from a low of about $65 million (in 2020) to a high of $81 million (in 2021), with an annual average of $72.7 million. Avista's programs for electric transmission investments are summarized by investment driver, discussed in more detail later in this report. Note that some projects may resolve issues under more than one category. While projects are categorized by a *principal* investment driver, a project that resolves multiple issues may be prioritized differently than it would be if under a single investment driver category.

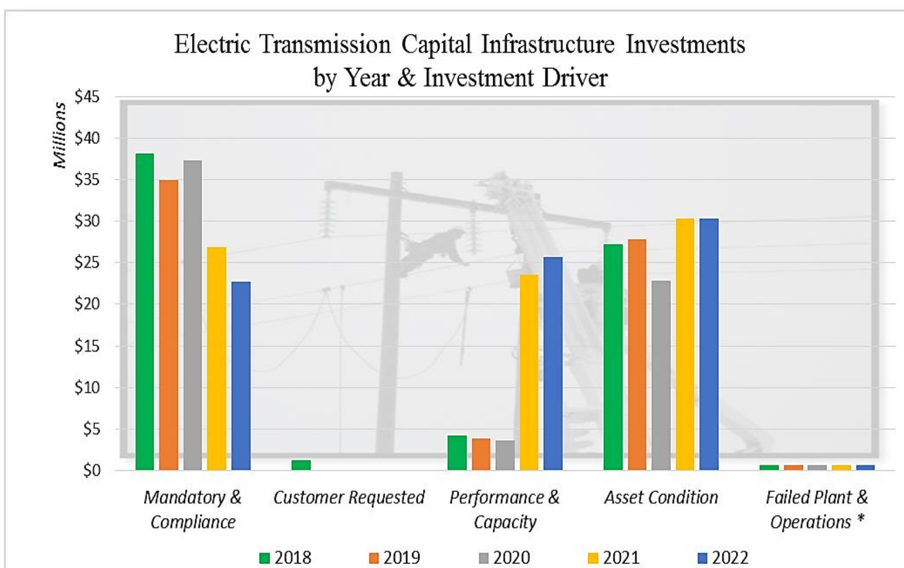


Figure 4. Total Planned Capital Transmission Expenditures 2018-2022

Planned Maintenance Expenditures

Over the next five years Avista plans to invest approximately $1.2 million annually in operations and maintenance programs designed to sustain its electric transmission system. Unexpected expenses are always a possibility, but the Company has routine maintenance programs in place to insure that those occurrences are as few as possible. Programs such as aerial and ground patrols to identify potential problems, fire retardant to protect poles from wildfire, foundation work to maintain the integrity of the structures, and vegetation management around lines and on access roads all help prevent outages. Each of these programs play a role in ensuring reliable service.

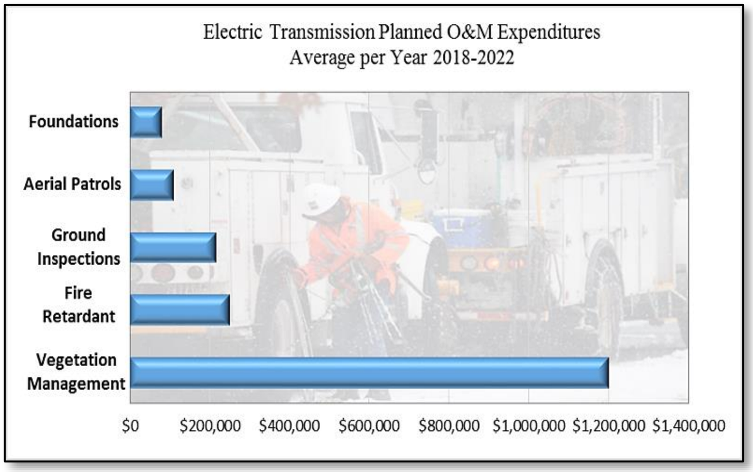
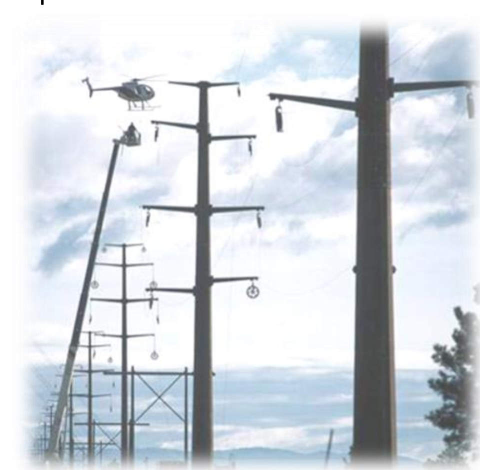


Figure 5. Average Planned O&M Transmission Expenditures

Conclusion

The year-over-year growth in the level of our prior period investments is not unusual compared with our peers across the utility industry. Our capital investments on a per customer basis are reasonably consistent with the industry, though our overall transmission spending pattern has trended below the industry average.

Avista's transmission infrastructure programs are thoughtfully developed, analyzed, optimized, adjusted, and re-analyzed as appropriate to ensure that we deliver cost effective value for our customers and meet all legal and mandatory requirements. This report also demonstrates that the level of our investments is somewhat conservative as a result of our need to balance transmission priorities with our other infrastructure demand, and the impact of these investments on our customers and our level of service.

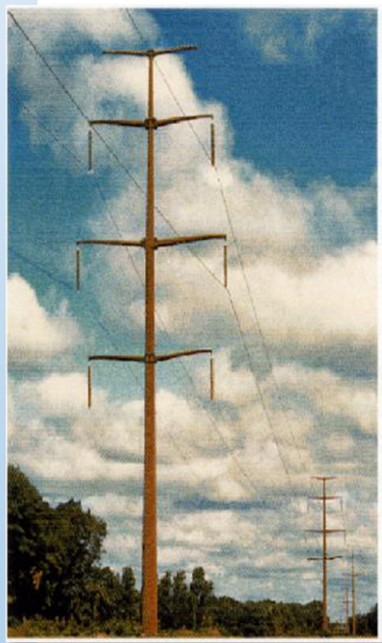


Report Key Objectives:

- *Provide a comprehensive summary of the need for capital investment and the plan for implementation;*
- *Explain factors driving Avista's need for increased investment;*
- *Simplify the understanding of the types of needs, or "investment drivers" shaping our investment plan;*
- *Provide visibility into why each capital project and program is necessary to meet our electric transmission system needs, and*
- *Provide a platform for continuous collaboration with our customers, Energy and Policy Staff, Commissioners, and a range of other Stakeholders.*

Introduction

Avista Utilities serves approximately 1.6 million electric and natural gas customers over 30,000 square miles, primarily in Eastern Washington and Northern Idaho, over 2,200 miles of high-voltage transmission lines and associated equipment. Avista must continually invest in its electric transmission system in order to provide the reliability our customers expect and deserve, at an affordable price, and that meets the requirements of numerous laws and regulations.



Though all of Avista's assets play a role providing the electricity that ultimately reaches consumers, in this report we have confined our discussion specifically to transmission facilities. Transmission is the physical energy delivery system that moves electricity from generation facilities to the substations where the voltage is stepped down to the distribution level so it can be delivered to customers. We have also included several operations and maintenance (O&M) programs such as Vegetation Management that play a key role in helping us provide safe and reliable service.

This report provides a summary overview of the Company's recent historic, current, and planned infrastructure investments in our electric transmission system for the period 2018 – 2022. Collectively these investments allow Avista to effectively respond to customer requests for new service or service enhancements, meet its regulatory and other mandatory obligations, replace equipment that is damaged or fails, support electric operations, address system performance and capacity issues, and replace infrastructure at the end of its useful life based on asset condition. Moreover, the investments described in the plan are based on what we know about our business today, including a range of precision in future cost estimates, applicable laws, regulatory requirements, and the capabilities of current technologies.

Avista Accountability to Customers

Prudent Investment - Avista demonstrates that the overall need, evaluations of alternatives, and the planned timing of implementation for each investment is carefully considered and in our customers' best interest. This report explains that the investments made to uphold the current reliability of the electric transmission system are conservative and cost effective for customers. Many of the investments are required in order to be in compliance with the federal, regional, state, and local entities that oversee our transmission operations. We believe this report demonstrates that our investments are needed and necessary in the timeframes planned in order to prudently serve our customers. It also notes identified and vetted needs for investment that are not fully funded in the current planning cycle in an effort to balance other priority investment needs.

Managing Our Costs - With the increasing levels of investments made by the Company in recent years, we have worked to mitigate the cost impact by moving to our present level of investment more gradually over a period of several years. This effort often requires Avista to fund programs at less than an optimum level during ramp up. The Company's efforts to manage the impact of these increasing infrastructure needs has allowed us to hold the annual increases in our customers' electric bill to a reasonable average of 1.9% over the past eight years. This keeps Avista's electric bills below the national average, below the average for Idaho since 2013, and below the average for electric customers in the state of Washington.[6]

Providing Reliable Electric Service – Avista is focused on maintaining a high degree of reliability as an important aspect of the quality of our service, particularly as our society becomes ever more reliant upon electronic technologies. Essentially, every utility has to define what "acceptable service reliability" is for its customers, striking a complex balance between customer's expectations, the investments that are needed to meet them, and overall system performance. Ideally, this mix creates the highest level of reliability performance that customers are willing to pay for in their rates. The expectations of customers can vary substantially from utility to utility, and there is a range of reliability levels that customers deem to be acceptable. Even within a utility's service territory, the reliability performance that is acceptable to customers can vary substantially by region. In Avista's experience, our customers are accustomed to the level of service reliability they have experienced in the area in which they live, and generally believe that to be reasonable for their locale. Avista's customer satisfaction surveys support this conclusion. In 2016 customers indicated 94% satisfaction with the overall service they receive from the Company. The number of complaints is also quite low, with only ten complaints filed in 2016.[7] Because it is expensive to achieve incremental levels of system reliability, and because these investments must be sustained over a period of many years before the benefit is realized, it is important to ensure that we are investing only the amount of money it takes to achieve an acceptable level of performance.

[6] The 1.9% includes all aspects of electric service. Statewide and national customer cost comparison information based on Edison Electric Institute Investor-Owned Utilities. Study available at https://www.myavista.com/about-us/our-rates-and-tariffs/about-rates

[7] Nine complaints were filed with the Company, one with the Commission directly. Washington Utilities and Transportation Commission, 151958-AVA-Comments-8-21-17

Overview of the U.S. Transmission System

The Electric System

The North American electrical grid is a highly complex and diverse system. It includes varied organizational structures and operating models (including multinational ownership), interdependent functions and systems, and multi-level authorities, responsibilities, and regulations. It is made up of generating facilities such as coal-fired and nuclear power plants, solar panels, wind turbines, natural gas-fired power plants, and hydroelectric dams. Transmission lines of various sizes carry the generated energy to substations. A complex distribution network takes the energy from the substations to the ultimate customer. An example is shown in the diagram below.[8]

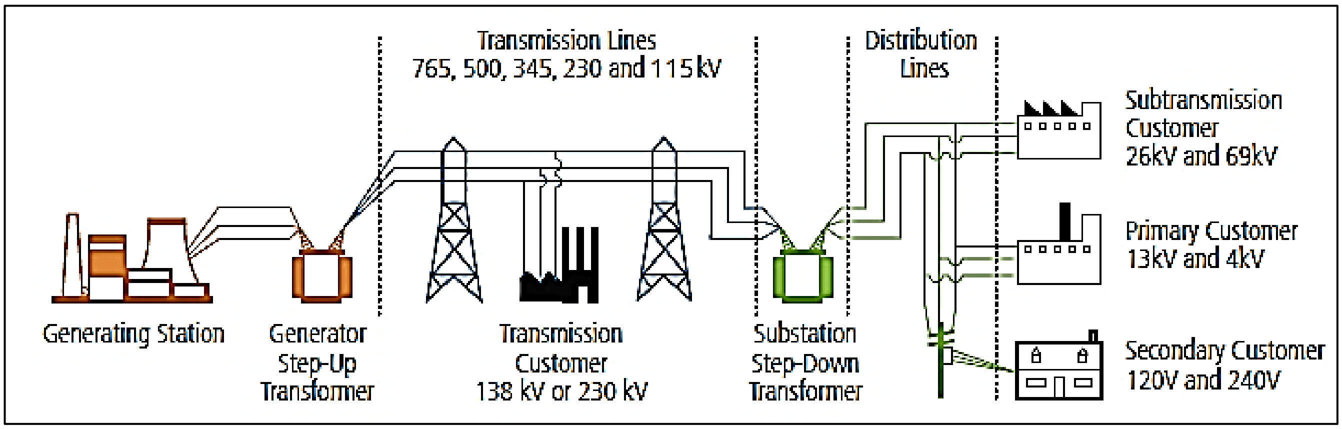


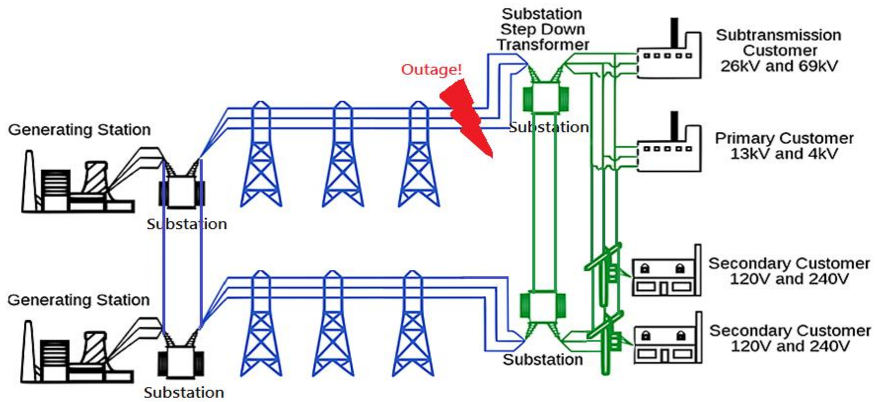
Figure 6. Basic Structure of the Electric System

When electricity is generated, typically at voltage levels similar to primary distribution customers, it is sent to a "step up" transformer in a substation outside the power plant where it is increased in voltage to allow it to travel more efficiently over long distances via transmission lines. At the distribution substation, the transmission line feeds a "step down" transformer that reduces the voltage before it enters the distribution system and goes on to the customer.

As electric current flows through a line, the resistance of the wires causes some of the energy to be dissipated in the form of heat (think of an electric space heater). This loss of energy is called active power line loss. By increasing the voltage on the line, typically to 110 kV or above, the required amount of electric current to transfer the same amount of energy is proportionally reduced, thus reducing line loss.[9] Increasing the diameter of the electric conductor also serves to reduce the amount of resistance and associated losses. Thus, high voltage transmission lines allow utilities to maximize the amount of energy that is ultimately delivered to the end user.

[8] Diagram courtesy of University of Idaho, "Principles of Sustainability." Chapter 6, http://www.webpages.uidaho.edu/sustainability/chapters/ch06/ch06-p3a.asp

[9] In the United States, the fraction of electricity lost in transit is about 6% for lines at 230 kV and below. Losses are reduced as voltage is increased. Lines at 345 kV typically suffer 4% losses, 500 kV lines are down to about 1.3% losses, and 765 kV and above are under 1%. However, new line and equipment designs are reducing these losses. https://www.dallasnews.com/business/health-care/2010/10/11/Electricity-lost-in-transmission-shows-up-3566



If an outage occurs on the top transmission line, customers can still be served from the second line (a redundant or looped feed system). Without the second transmission line, the top line customers would be without service until the line was repaired.

While electric reliability metrics of outage frequency and duration are measured at the distribution level of our system, the integrity and performance of our transmission system also plays a vital role in providing reliable service to Avista customers. Most transmission is configured to be loop-fed, which means that the electricity can be provided to a distribution substation from more than one direction (as shown in the illustration). In this configuration, a transmission outage will be isolated by substation equipment, the power will be rerouted to a different transmission line and on to customers. Thus the outage will have little or no effect on distribution facilities and customers. However, the reality of a modern electric system reflects a number of scenarios where transmission level reliability could directly affect distribution level reliability.

For example, some small rural substations have a single transmission feed and cannot be backed up by nearby distribution feeders or a second substation. This is called a radially fed substation (such as that shown in Figure 6 on the previous page). In this configuration, an outage to the transmission line can put the entire substation and its associated distribution system out of service.

Industry Challenges

The utility industry has never faced the onslaught of challenges it is dealing with today. Even as demand and cash flow shrink, utilities must weigh significant capital investments in transmission and distribution lines in order to maintain reliability, update outmoded systems, and address 21st-century concerns like cybersecurity. In addition, utilities must manage:

	Avista	Nation
Transformer > 25 years old	63%	70%
Circuit Breakers > 30 years old	40%	60%
Transmission Lines > 25 years old	88%	70%

- **Aging Infrastructure**. Thousands of transformers, reactors, capacitors, conductors, poles and structures are well past their expected lifespan.[10] The U.S. Department of Energy (DOE) estimates that, nationwide, 70% of transformers are 25 years old or older, 60% of circuit breakers are more than 30 years old, and 70% of transmission lines are 25

[10] For more information about the primary equipment used in the transmission system, please see Appendix J (page 97).

years old or older and approaching the end of their useful life. This critical situation continues to build, driven by a lack of investment in transmission infrastructure, which declined 44% between 1980 and 1999.[11]

- **Low and Shifting Demand** is reducing sales and revenues. The 2017 Annual Energy Outlook from Edison Electric Institute projects a decrease in load growth for the next several years, as can be seen in Figure 7. EEI projects total electricity sales to rise 0.7% annually, with the residential sector projected to grow by 0.3% per year, the industrial sector to grow by 1.1% per year, and the commercial sector expected to decline by 0.3% per year.[12] EEI attributes this slow growth to energy efficiency and a move toward less electricity-intensive industries. This situation sharply reduces earnings growth for utilities.

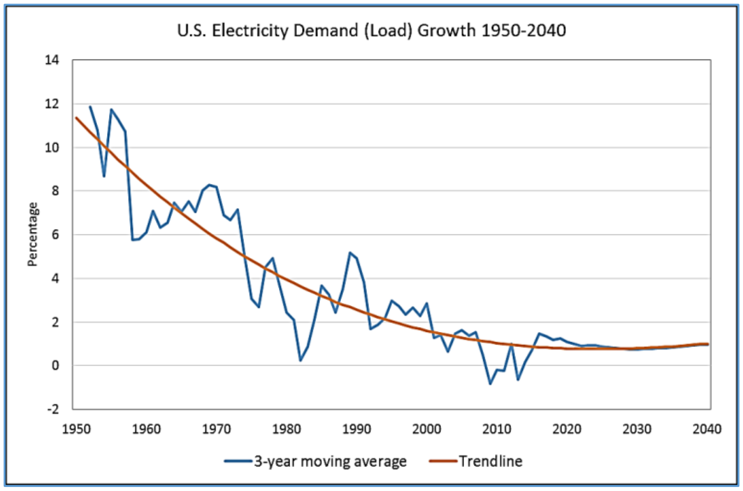


Figure 7. U.S. Electricity Demand Growth [13]

For utilities like Avista, the load mix is also shifting. The State of Washington legalized growing marijuana, which is a highly power intensive operation requiring 24-hour lighting, heating, air conditioning and ventilation systems. As an example of the impact, Denver's 362 marijuana growing facilities consumed more than 2% of the entire city's electrical usage. City planners estimate that a 5,000 square foot indoor facility consumes approximately 29,000 kWh of electricity as compared to a local household which would consume about 630 kWh.[14] Data centers have similar high-energy usage profiles. As an example, when Microsoft located a data center in Quincy, Washington in 2007 they requested that Grant County Public Utility District provide a substation capable of 48 million watts, about enough power to serve 29,000 American homes, according to an analysis done by the Electric Power Research Institute. A large data center can use as much electricity as a small town, with a power density 100 times more than a typical large commercial customer.[15]

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[11] "Transmission & Distribution Infrastructure," A Harris & Company, Summer 2014, http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf. For information on the specific equipment referred to, please see Appendix J "Transmission System Equipment" beginning on page 97 or the Glossary in Appendix Z beginning on page 103.
[12] Edison Electric Institute 2017 Annual Energy Outlook, https://www.eia.gov/outlooks/aeo/ and the Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=26672
[13] Data for this chart from the EEI 2017 Annual Energy Outlook: https://www.eia.gov/outlooks/aeo/
[14] Melanie Sevcenko, "Pot is Power Hungry: Why the Marijuana Industry's Energy Footprint is Growing," The Guardian, February 27, 2016, https://www.theguardian.com/us-news/2016/feb/27/marijuana-industry-huge-energy-footprint
[15] James Glanz, "Data Barns in a Farm Town, Gobbling Power & Flexing Muscle," The New York Times, September 23, 2012, http://www.nytimes.com/2012/09/24/technology/data-centers-in-rural-washington-state-gobble-power.html and "Facts and Stats of World's Largest Data Centers," Storage Servers, July 17, 2013, https://storageservers.wordpress.com/2013/07/17/facts-and-stats-of-worlds-largest-data-centers/

➢ **Regulatory pressure** is focused on retail energy prices, green technologies and more customer control. A 2015 PriceWaterhouseCooper Power and Utilities Survey indicated that uncertainty in regulatory policies and regulations are the primary risk facing utilities.[16] According to the survey, allowed return on equity (ROE) has been consistently dropping throughout the industry since the 1980s, although the need for capital investment is increasing, creating tremendous tension. Though regulators maintain close scrutiny over rates they are "freely encouraging the development of renewables and greater customer access to the grid, distribution channels, and equipment through emerging technologies."[17] These technologies require expensive investments and infrastructure. In addition, as will be discussed in later sections, national and regional regulations and requirements are increasing in number, each requiring Avista to respond in the way we operate and do business.

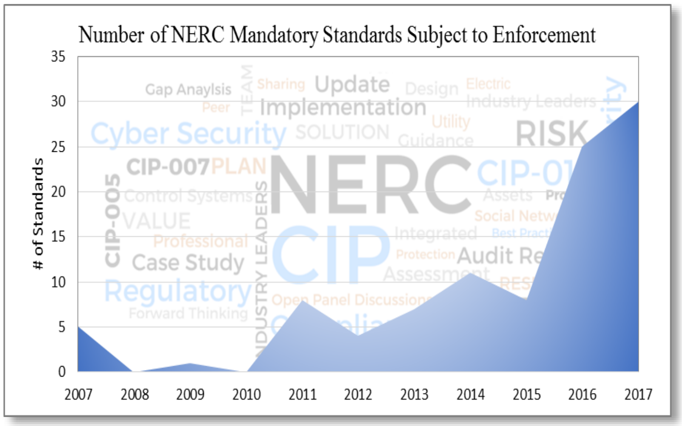

Figure 8. Number of NERC Mandatory Standards

Today's federal operating standards presume that the nation's transmission infrastructure is sufficiently robust at this time, allowing it to comply with the ever more restrictive operations standards and additional uses put forth by the Federal Energy Regulatory Commission (FERC). That is simply not the case. According to the American Society of Civil Engineer's 2017 Infrastructure Report Card, much of the U.S. energy system was constructed in the 1950s and 1960s and more than 640,000 miles of aging high-voltage transmission lines in the lower 48 states' power grids are at full capacity.

The U.S. Power Grid by the Numbers

- *Technology dates back to 1950s - 1970s*
- *Over 7,000 power plants*
- *Over 5 million miles of transmission & distribution lines*
- *68-73% of all major outages are weather related*
- *More blackouts than any other developed nation (today having 285% more outages than occurred in 1984)*
- *Average price 12¢/kWh*
- *3,300 utilities*
- *150 million customers*
- *Valued at $876 billion[18]*

In addition to feeling its age, the integrated grid, designed to accommodate very steady, very stable traditional resources, is now required to integrate non-traditional and often unpredictable resources, smart grid technology and emerging technologies such as energy storage, electric cars and distributed systems. At the same time, the grid is facing cyber threats never imagined back in the 1950s and 1960s when most of the system was built.

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[16] PriceWaterhouseCooper (PWC) "Global Power & Utilities Survey, 2015: Key Challenges", https://www.pwc.com/gx/en/industries/energy-utilities-mining/power-utilities/global-power-and-utilities-survey/key-challenges.html
[17] Earl Simpkins, Leslie Hoard, Suva Chakraborty, Daniel Wilderotter, "Utilities Preparing for Growth: Navigating Disruption By Linking Capabilities," November 20, 2015, https://www.strategyand.pwc.com/reports/utilities-preparing-for-growth
[18] Herman K. Trabish, "US Utilities Are Beginning to Remake the Nation's Grid," UtilityDive, July 15, 2014, https://www.utilitydive.com/news/us-utilities-are-beginning-to-remake-the-nations-grid/285916/ based on data from the Edison Electric Institute.

According to a variety of studies across the United States, the viability of the century old bulk power grid has been declining and is "nearing the end of its useful life." They note that depreciation is exceeding new investment, even with all of the large projects being built nationwide. Further, they state that: "Legislative and regulatory barriers based upon environmental and sustainability concerns constrain, even prevent, the siting, construction and operation of new grid facilities." [19] The cost of new infrastructure is increasing and any significant new construction means higher rates to consumers in an increasingly competitive environment. Utilities face significant risk of not recovering all their costs, much less an adequate return, for new infrastructure investment.[20]

Utilities are pulled to economize and pushed to innovate, dealing with decreasing revenues and, at the same time, expensive and revolutionary new technologies such as distributed generation, battery storage technology, customer-requested technologies, and integrating intermittent renewable resources.[21]

Federal Transmission Standards: Operations

Avista has been hit particularly hard by tightening federal standards governing our transmission operations. The primary impact has been a significant loss in the operational flexibility once relied upon to ensure stability of the grid during unusual operating conditions, usually involving line or substation outages. As an example, by judiciously using its past operating flexibility based on the standard operating practices of the time, the Company was able to take short-term remedial actions to manage through unexpected outages, thereby avoiding making expensive investments in transmission infrastructure to mitigate infrequent system outages. Consequently, the more restrictive operating requirements mandated by federal standards now necessitate construction of new infrastructure or rebuilding existing infrastructure to mitigate the potential for loss of customer service.

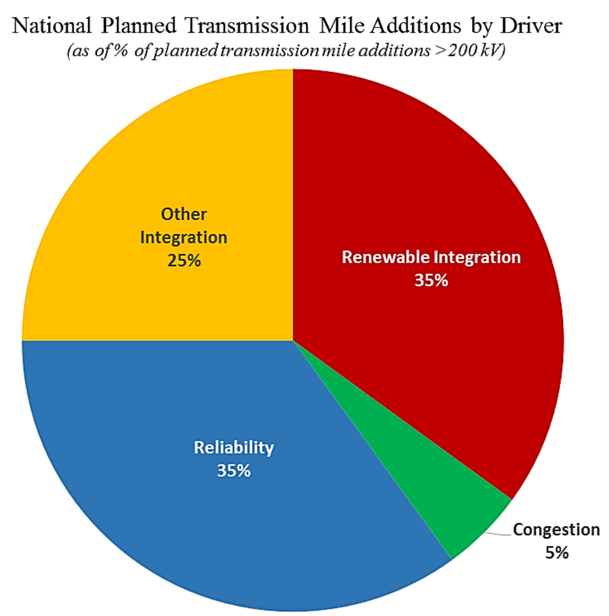


Figure 9. National Planned Transmission Additions Indicating the Impact of Federal Regulations Regarding Reliability and Renewable Resource Integration[22]

The tightening of the operating standards has simply outpaced Avista's ability to make the significant capital investments needed to reasonably comply. "Reasonably comply" here means without bearing

[19] Earl Simpkins, Leslie Hoard, Suva Chakraborty, Daniel Wilderotter, "Utilities Preparing for Growth: Navigating Disruption By Linking Capabilities," November 20, 2015, https://www.strategyand.pwc.com/reports/utilities-preparing-for-growth
[20] Ibid.
[21] "Electric Utilities Are Facing Unprecedented Challenges," Seeking Alpha, January 18, 2016, https://seekingalpha.com/article/3816936-electric-utilities-facing-unprecedented-challenges and Tom Flaherty, Norbert Schwieters and Steve Jennings, "2107 Power and Utilities Trends," https://www.strategyand.pwc.com/trend/2017-power-and-utilities-industry-trends
[22] Data for this chart from "Transmission & Distribution Infrastructure," http://www.harriswilliams.com/sites/default/files/industry_reports/final%20TD.pdf

undue additional stress and risk to equipment, or having to operate in an emergency mode in order to avoid a violation and suffer the significant resulting financial penalties. As a result of this mismatch in system capability and operating restrictions, the Company must develop and undertake relatively short-term, urgent investment strategies which, while prudently serving the immediate need to be compliant, may not provide the optimum long-term solutions from a facility planning perspective or a customer rate basis.

Federal Transmission Standards: Planning

Electric utilities must also comply with more stringent federal transmission planning requirements, which, like the FERC operating standards, also come with attached penalties for noncompliance. These planning standards rely on conventional forecasts of load growth and modeling of the electric system. They focus on the type of transmission system improvements needed to operate in accordance with the federal operations standards a decade or more into the future. Though the planning standards do not stipulate what investments must be made, they do require the Company to prove it has timely completed the required studies, and to demonstrate that it is making reasonable progress making the transmission investments identified in the planning studies.

Because the focus of planning is to create an adequate and robust system for the future (from a holistic system perspective) it is necessarily disconnected from today's operational limitations and the current critical needs of the system. In an ideal world, the operating limitations of today's system would be remedied in the long-term infrastructure plan developed by sufficient planning. However, that does not address the needs of providing compliant load service today. It's not that this disconnect is a bad thing; however, it requires the Company to rationalize sometimes incongruent and competing needs and to make certain it provides the capital funding necessary to achieve compliance in both current operations and future planning. Though the Company is making great strides in better rationalizing these competing needs through formalized processes such as the Engineering Roundtable (discussed earlier), it still has not been able to provide the capital required to adequately fund the needs identified by each function.

Growing Need for Investment Based on Asset Condition

Irrespective of the investments needed to plan for and operate our electric transmission system in compliance with federal standards, the Company and the industry in general face the growing need for reinvestment in transmission based upon the replacement of assets that have reached the end of their useful life. Much of the nation's transmission system was constructed before 1970, with an expected

[23] Herman K. Trabish, "US Utilities Are Beginning to Remake the Nation's Grid," UtilityDive, July 15, 2014, https://www.utilitydive.com/news/us-utilities-are-beginning-to-remake-the-nations-grid/285916/ based on data from the Edison Electric Institute.

service life of 50 years.[24] Approximately 63% of Avista's electric transmission lines are more than 50 years old; 88% are over 25 years old. In addition, these lines were built to provide traditional utility service: moving energy from the power plant to the substation, without consideration to the integration of intermittent resources, the development of the energy open market, or the issues created by increasing regulation. These matters are driving required transmission investment nationwide, as shown in Figure 10.

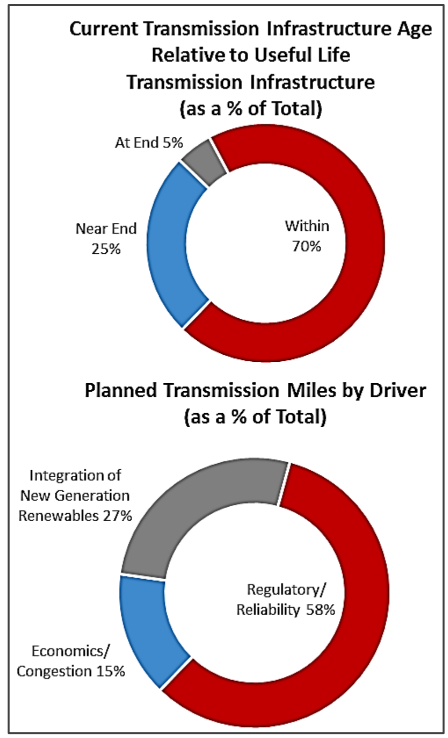


Figure 10. U.S. Transmission Structure Age and Construction Drivers [25]

This pattern of growth in the need for new investment reflects the significant expansion of the electric system during the economic boom following the end of World War II. During this period, which continued as late as the early 1980s, the annual plant additions to the system dwarfed those investments made before the war. So while the industry and Avista have for many years been replacing end-of-life transmission and other infrastructure, we have entered a period where the amount of material that must be replaced is increasing each year, and it will continue to do so for the next two decades at least. While some of these asset condition investments may serve the needs of transmission planning and operations, they tend to be separate and distinct, and as such, represent another significant competing driver for limited the capital required to fund priority needs across the business.[26]

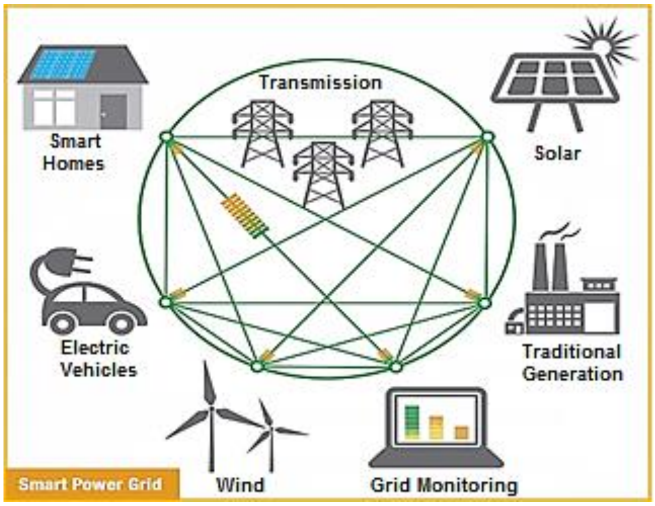
Third-Party Transmission Requirements and Growing Uncertainties

Today's electric utility is also under federal obligation to provide transmission interconnections and related investments required to serve the needs of non-utility, non-customer, private business interests. While it is assumed that these private transmission users will pay for the investments they require over the term of their contracts, this concept presumes that they remain in business long enough to do so. It also supposes that the transmission rates for these users, which are established by Federal Energy Regulatory Commission, fairly allocate the costs between Avista's customers and these third-party users. But even more importantly, the requirement to make the investments needed to provide these interconnections (and associated capacity) competes directly with the utility's primary capital needs to support operations, planning, asset replacements, failed plant, and its own customer base in an increasingly constrained capital environment.

[24] American Society of Civil Engineers, "2017 Infrastructure Report Card," https://www.infrastructurereportcard.org/cat-item/energy/
[25] This data is from "Transmission & Distribution Infrastructure", http://www.harriswilliams.com/sites/default/files/industry_reports/final%20TD.pdf
[26] For more information about national grid condition, see Meagan Clark, "Aging US Power Grid Blacks Out More Than Any Other Developed Nation," July 17, 2014, International Business Times, http://www.ibtimes.com/aging-us-power-grid-blacks-out-more-any-other-developed-nation-1631086 and Steve Brachmann, "America's Aging Electrical Grid Could Benefit from Smart Grid Tech," April 4, 2016, http://www.ipwatchdog.com/2016/04/04/aging-electrical-grid-smart-grid-tech/id=67934/ and Tara Dodrill, "Study: US Power Grid Has More Blackouts Than ENTIRE Developed World," http://www.offthegridnews.com/grid-threats/study-us-power-grid-has-more-blackouts-than-entire-developed-world/

New Technology

Another dynamic facing electric utilities today is the uncertainty generated by the emerging business model, which is focused on decentralizing traditional utility function in order to create a new integrated grid-services platform of the future. While for some time now the thinking has been that the promotion of new technologies like distributed resources might help offset the need for pending grid reinforcements, the nascent reality is that customers, armed with a range of new technologies, are desiring new services and flexibility that go well beyond any notion of maintaining the conventional grid with just a few tweaks here and there.[27] While our Company has been a pioneer of sorts and a promoter of the development of these ideas, these concepts create uncertainty about the long-term used and usefulness of the infrastructure investments we make today. This is the case because the assets that comprise the transmission and distribution system generally have very long lives. As customers continue to exercise greater choice in how they meet their personal energy needs, and laws and rules continue to adapt to support that, it places increasing degrees of uncertainty around long-term usefulness as well as the potential for stranding today's investments.



Avista is actively engaged in addressing these industry changes, including collaborating with regulators and customers to provide the services they are demanding. Examples include a recently redesigned website and an outage phone app. Avista is also developing additional renewable resources to add to the traditional resource portfolio, teaming up with the University of Idaho and Washington State University to develop a microgrid in downtown Spokane,[29] and creating a groundbreaking urban renewal project in Spokane to pilot a variety of

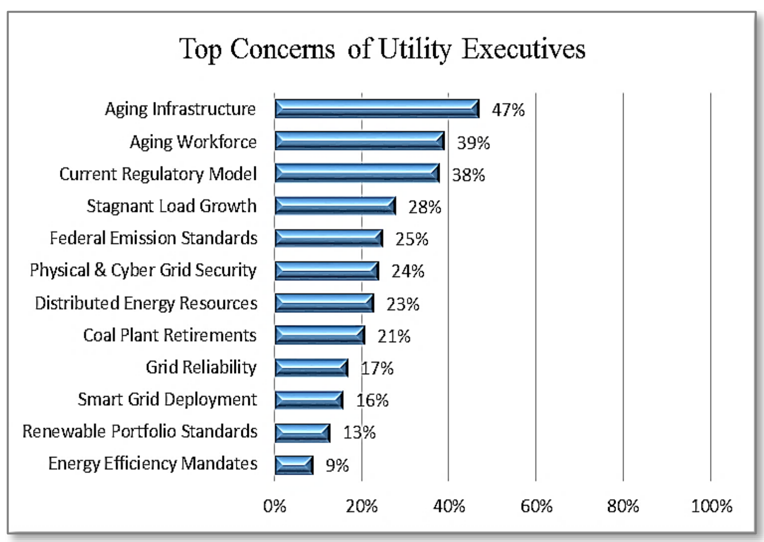


Figure 11. Top Concerns of Utility Executives [28]

[27] "Smart Power Grid" graphic courtesy of John Toon, Georgia Institute of Technology, https://phys.org/news/2014-02-lessons-biggest-blackouts-history.html
[28] "State of The Electric Utility Survey Results" UtilityDIVE (Survey of over 400 U.S. Electric Utility Executives) - https://www.slideshare.net/wyakab/utility-2015
[29] Elisa Wood, "Avista to Test Economic Model for Utility Microgrids," September 30, 2016, https://microgridknowledge.com/utility-microgrids-avista/ and "Spokane Microgrid Distributed Generation and Storage," http://mindworks.shoutwiki.com/wiki/Spokane_Microgrid_Distributed_Generation_and_Storage

potential utility assets, including smart meters, distributed generation, and battery storage.[30] At the same time, the Company is pragmatically managing and balancing its existing and foundational assets in a way that meets traditional needs.

Avista is faced with the same questions the entire utility industry is dealing with today: does it make sense to pursue strategies such as the development of new high-voltage power lines that may reinforce an outdated paradigm of electricity delivery, or should scarce dollars be spent on new but emerging technology such as distributed generation? Uncertainty exists all around us: the potential for increased renewable portfolio standards, growing environmental issues surrounding renewable energy resources,[31] changing customer behaviors and expectations, new technologies such as automation, smart grid, smart meters, the internet-of-things,[32] automation, electric vehicles, distributed grid,[33] pressure on coal, etc. The list is extensive and expensive, making this an agonizing quandary as so much is at stake. Since no crystal ball is available, Avista has developed strategies and plans the Company believes are rational, measured, thoughtful, and conscientious in doing what is right for the long-term health of the Company and its customers. We will discuss these approaches in the following pages.

Trends in Transmission Reliability

The North American electric grid is one of the most impressive and complex engineering feats of the modern era. It has been called the world's largest machine, comprising over 5,800 power plants, 70,000 substations[34], six million miles of distribution lines,[35] and 640,000 miles of high voltage transmission power lines[36] serving nearly 300 million customers in the United States,[37] and all managed by over 3,200 organizations.[38] It is made up of three primary grids: Eastern, Western, and Texas. It is estimated that the value of this machine is in the range of $1.5 to $2 trillion, with a

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[30] "Spokane's Urbanova Set to Drive Innovation and Economic Development for Cities of the Future," October 3, 2016, http://www.uetechnologies.com/news/83-spokane-s-urbanova-set-to-drive-innovation-and-economic-development-for-cities-of-the-future and Jeff St. John, "How Spokane Is Building a Smart City From the Grid Out, With Transactive Energy Included," November 14, 2016, https://www.greentechmedia.com/squared/read/how-spokane-is-building-a-smart-city-from-the-ground-up-with-transactive-en#gs.p65vyBM

[31] For more information: Union of Concerned Scientists, "Environmental Impacts of Renewable Energy Technologies," https://www.ucsusa.org/clean-energy/renewable-energy/environmental-impacts#.Wl-lXWckumQ

[32] The Internet-of-Things is the concept of putting computing devices into everyday objects, such as cellphones, cars, washing machines, lamps, etc., allowing connection of any device with an on and off switch to the Internet and/or to each other.

[33] It is interesting to note that there are ripple effects to the utility from distributed grid. For example, a study by Black and Veatch found that a utility may have to add 17% of more transformers to their system to allow for this technology. See: "Disruptive Technologies and the Future of the Utility Business Model," https://www.slideshare.net/blackveatch/disruptive-technologies-and-the-future-of-the-utility-business-model. New technologies do not come without cost.

[34] A. Harris Williams, "Transmission & Distribution Infrastructure," 2010, page 7, http://www.harriswilliams.com/sites/default/files/industry_reports/final%20TD.pdf

[35] Ibid. Page 2.

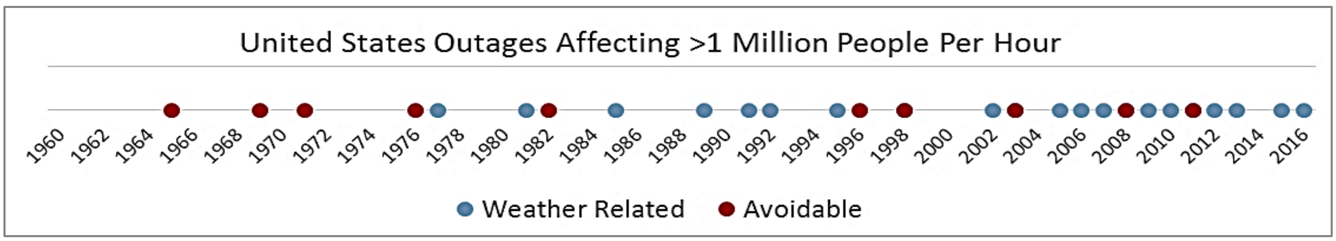
[36] James McBride, "Modernizing the U.S. Energy Grid," January 26, 2016, Council on Foreign Relations, https://www.cfr.org/backgrounder/modernizing-us-energy-grid

[37] A. Harris Williams, "Transmission & Distribution Infrastructure," 2010, http://www.harriswilliams.com/sites/default/files/industry_reports/final%20TD.pdf

[38] While investor-owned utilities make up only 6% of the number of electricity providers, they serve 68% of electric customers, https://www.infrastructurereportcard.org/wp-content/uploads/2017/01/Energy-Final.pdf

replacement cost approaching $5 trillion.[39] This energy delivery system is the bridge between electricity generation and consumption. It transmits power generated from a variety of sources and moves it to end users every minute of every day. It is a living entity, constantly changing, with different sources of electricity being generated, bought, sold, and manipulated to instantly satisfy the demands of the users. Most of the time it operates invisibly in the background while providing the essential services that underpin American society. This system is the essential foundation of life-enabling, life-sustaining infrastructure. It is considered "uniquely critical"[40] by the White House due to enabling and supporting other vital infrastructure sectors, including oil and natural gas, water, transportation, communications, and the financial sector.

Originally constructed to serve local customers, the U.S. grid now moves energy nationally across an aging system. The grid was neither originally engineered to meet today's demand, nor increasingly severe weather events.[41] It is currently operating at or near full capacity. According to the American

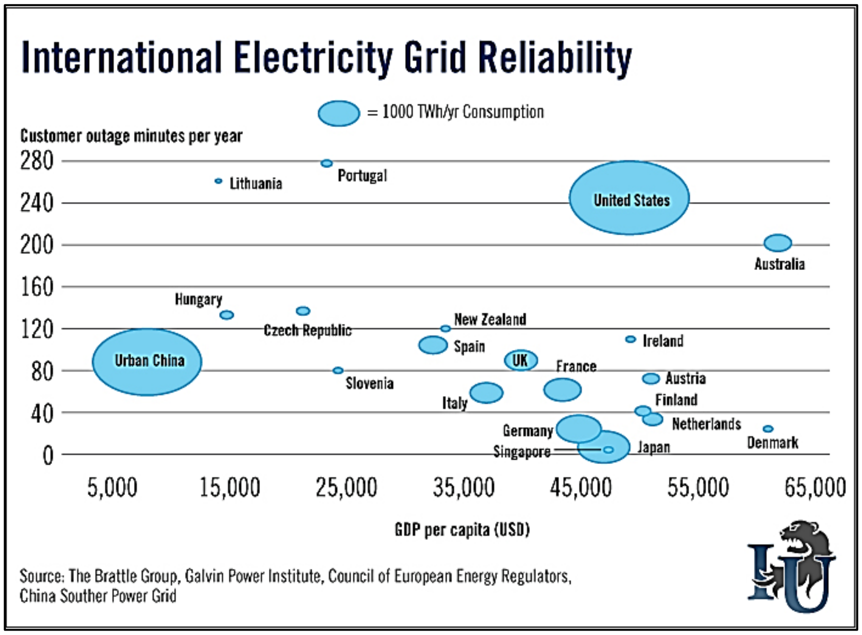


Society of Civil Engineers in their 2017 Infrastructure Report Card,[42] the energy sector in the United States faces serious challenges due to aging infrastructure. There are also resiliency issues related to severe weather events, which they believe pose a threat to both public safety and the national economy. Their studies show that between 2003 and 2012, weather-related outages coupled with aging infrastructure are estimated to have cost the U.S. economy an inflation-adjusted annual average of $18 billion to $33 billion. Their analysis indicates that in 2015, Americans experienced a reported 3,571 total outages with an average duration of 49 minutes. Backing up these findings is a report to the White House prepared by the President's Council of Economic Advisors, which states that extreme weather is currently "the number one cause of power outages in the United States, causing an astonishing 87% of outages affecting more than 50,000 people."[43]

> *"A robust electric transmission grid is essential to achieving the vision of an energy future that I believe most of us share."*
>
> \- FERC Chairman Jon Wellinghoff, 2010

[39] Joshua D. Rhodes, "The Outdated US Electric Grid is Going to Cost $5 Trillion to Replace," March 16, 2017, Business Insider, http://www.businessinsider.com/replacing-us-electrical-grid-cost-2017-3
[40] "Presidential Policy Directive – Critical Infrastructure Security and Resilience," February 12, 2013, https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil
[41] For more information regarding increasing numbers of severe weather events, please see Appendix G on page 91.
[42] "American Society of Civil Engineers, 2017 Infrastructure Report Card: Energy", https://www.infrastructurereportcard.org/wp-content/uploads/2017/01/Energy-Final.pdf
[43] "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages," President's Council of Economic Advisers, the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability and the White House Office of Science and Technology, 2013, https://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf

Noting that the U.S. grid is an "aging and complex patchwork system," the American Society of Civil Engineers states: "Without greater attention to aging equipment, capacity bottlenecks, and increased demand, as well as increasing storm and climate impacts, Americans will likely experience longer and more frequent power interruptions." Their Report Card estimates the cumulative investment gap between 2016 and 2025 to be $177 billion, while at the same time "utilities face considerable pressure to cover maintenance and system upgrade costs through regulator-capped rate increases, and thus struggle to justify more reliable lines or make long-term investments."[44] Another study, this one performed by the Brattle Group and commissioned by the Edison Electric Institute, suggested that approximately $298 billion in new transmission will be required over the period 2010 to 2030 to replace aging infrastructure and meet increasing demands on the grid.[45]



International Electricity Grid Reliability[46]

According to federal data, the U.S. electric grid loses power 285% more often now than it did in 1984 when data collection on blackouts began.[47] That is estimated to cost American businesses as much as $188 billion per year.[48] According to experts this is primarily due to aging infrastructure, including reliance on technologies developed in the 1960s and 1970s.[49] Analysis indicates that at least 25% of America's power assets are of an age in which condition is a concern.[50] According to the Edison Electric Institute:

> *"Transmission investments provide an array of benefits that include: providing reliable electricity service to customers, relieving congestion, facilitating robust wholesale market competition, enabling a diverse and changing energy portfolio and mitigating damage and limiting customer outages during adverse conditions.*

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44 "American Society of Civil Engineers, 2017 Infrastructure Report Card: Energy", https://www.infrastructurereportcard.org/wp-content/uploads/2017/01/Energy-Final.pdf

45 "Transforming America's Power Industry: The Investment Challenge 2010-2030," The Brattle Group, November 2008, page 5, http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry_Exec_Summary.pdf

46 Source of this graphic: http://www.investmentu.com/article/detail/44798/chart-cybersecurity-united-states-electricity-grid#.WbqQRWckuUk Interesting note: China is now the #1 consumer of electricity in the world and has been since 2009. Global Energy Statistical Yearbook 2017: https://yearbook.enerdata.net/total-energy/world-consumption-statistics.html

47 Megan Clark, "Aging US Power Grid Blacks Out More Than Any Other Developed Nation," July 2014, http://www.ibtimes.com/aging-us-power-grid-blacks-out-more-any-other-developed-nation-1631086

48 Massoud Amin, "Asset Management, ROI, Risks, Resilience, and Security," Session 1, June 2017, Institute of Electrical and Electronics Engineers (IEEE), http://resourcecenter.smartgrid.ieee.org/sg/product/education/SGTUT0005

49 Megan Clark, "Aging US Power Grid Blacks Out More Than Any Other Developed Nation," July 2014, http://www.ibtimes.com/aging-us-power-grid-blacks-out-more-any-other-developed-nation-1631086

50 Massoud Amin, "How To Save Aging Assets," 2015, http://www.midwesterngovernors.org/EnergyStorage/Meeting/HowToSaveAgingAssets.pdf

New transmission investments also deploy advanced monitoring systems and other new technologies designed to ensure a more flexible and resilient grid. At the same time, all transmission projects support local systems in order to maintain the paramount objective of providing reliable electricity service to customers. A robust transmission system is needed to provide the flexibility that will enable the modern electric system to operate. Although much transmission has been built to enhance reliability and meet customer needs, continued investment and development will be needed to provide that flexibility."[51]

The Need for a Robust Transmission Grid

The public policy benefits of transmission investment are becoming increasingly clear. There are numerous advantages of a robust transmission system, which have been recognized by Congress,[52] the Administration,[53] and the Federal Energy Regulatory Commission (FERC).[54] People are dependent upon electricity for almost every aspect of their daily lives and people cannot imagine modern life without it! The electrical transmission grid is an integral component of this system and must constantly change and grow to meet increasing demands, new generation resources, and enhanced reliability regulation and requirements.

> "As I have repeatedly stressed, this nation should have policies that encourage needed investment in transmission projects. The new construction of transmission lines is often the lowest-cost way to improve the delivery of electricity service. By building needed transmission, our electrical service can maintain reliability at levels that are the envy of the world, while simultaneously improving consumer access to lower cost power generation – all while permitting more efficient and cost-effective renewable resources to compete on an equal basis with traditional sources of power."
>
> - *FERC Commissioner Philip Moeller*

FERC continues to articulate public policy reasons for additional investment in transmission infrastructure. With the issuance of Order No. 1000, the Commission stated that "additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs" and that "it must act promptly to establish the rules and processes necessary to allow public utility transmission providers to ensure planning of and

[51] "Transmission Projects: At A Glance," Edison Electric Institute, December 2016, http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_executivesummary.pdf

[52] H.R.6 Energy Policy Act of 2005, Public Law No: 109-58 (08/08/2005), https://www.congress.gov/bill/109th-congress/house-bill/6 sets forth an energy research and development program to promote stability and reliability in the American interconnected system with tax incentives, loan programs, additional authority for the Department of Energy, etc.

[53] U.S. Department of the Interior, October 5, 2011, "Obama Administration Announces Job-Creating Grid Modernization Pilot Projects" from Ken Salazar, Secretary of the Interior: "Transmission is a vital component of our nation's energy portfolio, and…serve as important links across our country to increase our power grid's capacity and reliability…This is the kind of critical infrastructure we should be working together to advance in order to create jobs and move our nation toward energy independence." Department of Energy, June 13, 2011, "Energy Secretary Chu Announces Five Million Smart Meters Installed Nationwide as Part of Grid Modernization Effort, https://energy.gov/articles/energy-secretary-chu-announces-five-million-smart-meters-installed-nationwide-part-grid. Energy Secretary Steven Chu: "To compete in the global economy, we need a modern electricity grid….An upgraded electricity grid will give consumers choices and promote energy savings, increase energy efficiency, and foster the growth of renewable energy resources."

[54] Testimony of Chairman Jon Wellinghoff, Federal Energy Regulatory Commission, Before the Energy and Environment Subcommittee Of the Committee on Energy and Commerce, United States House of Representatives, Oversight Hearing for the Federal Energy Regulatory Commission, March 23, 2010, https://www.ferc.gov/CalendarFiles/20100323141517-Wellinghoff-3-23-10.pdf quotes Chairman Wellinghoff: "A robust electric transmission grid is essential to achieving the vision of an energy future that I believe most of us share." Federal Energy Regulatory Commissioner Philip Moeller, quoted on May 19, 2011: "As I have repeatedly stressed, this nation should have policies that encourage needed investment in transmission projects. The new construction of transmission lines is often the lowest-cost way to improve the delivery of electricity service. By building needed transmission, our electrical service can maintain reliability at levels that are the envy of the world, while simultaneously improving consumer access to lower cost power generation – all while permitting more efficient and cost-effective renewable resources to compete on an equal basis with traditional sources of power." https://www.ferc.gov/EventCalendar/Files/20110519115137-E-9-Moeller.pdf

investment in the right transmission facilities as the industry moves forward the many challenges it faces."[55] FERC is responsible for promoting a strong national transmission infrastructure, and establishes rules to support electric reliability and lower costs to consumers by reducing transmission congestion.[56]

The U.S. Congress is paying increasing attention to the resilience and security of the grid as well. Last July, the U.S. House of Representatives passed legislation designed to strengthen the U.S. electric grid, recognizing that the grid is critical to all Americans and that it is right out in the open, visible to citizens every day and thus vulnerable to a wide variety of threats. Every U.S. President since 1990 has acknowledged that U.S. infrastructure risks are high. Finally Congress is taking action, creating a bill that offers the necessary funding to increase the resiliency of the grid and to provide a comprehensive, national plan to protect it.[57] This bill is currently being discussed in the Senate. Regardless of the final outcome, it is apparent that the energy business and, in particular the grid, is under increasing scrutiny and evaluation, and that will likely bring changes to electric utilities across the nation.

> *"A reliable and resilient electrical grid is critical not only to our national and economic security, but also to the everyday lives of American families."*
>
> - U.S. Secretary of Energy Rick Perry

National Historic Investment in Electric Transmission

As mentioned earlier, the bulk of Avista and the nation's energy delivery systems were constructed in the period after World War II and generally into the 1970s and 1980s[58] when economic growth and expansion fueled the demand for new energy infrastructure.[59] Nationwide, utility investment generally slowed during the 1990s. This slowdown was attributed to several factors, particularly the uncertainty around disaggregation of vertically-integrated utilities and concerns of how new plant investment might be treated under the then-impending federal utility deregulation. Another driver of reduced spending was the opportunity to take advantage of the robust capacity in distribution, transmission, and generation resources built up in prior decades. By the late 1990s, however, the country's utility industry recognized the need for increased investment to keep pace with customer growth, to replace or rebuild aging facilities, and to meet increasing customer and regulatory expectations for greater power quality and system reliability.

Using a helicopter to rebuild the 60 year old Benewah – Moscow Line

[55] United States of America Federal Regulatory Commission 18 CFR Part 35, May 17, 2012, i, pages 9 and 10.
[56] FERC Transmission Investment: https://www.ferc.gov/industries/electric/indus-act/trans-invest.asp
[57] "House Bill to Protect, Strengthen U.S. Electric Grid is Important First Step," July 21, 2017, https://www.prnewswire.com/news-releases/house-bill-to-protect-strengthen-us-electric-grid-is-important-first-step-300492357.html and H.R.2507 - 21st Century Power Grid Act, 115th Congress, https://www.congress.gov/bill/115th-congress/house-bill/2507/text
[58] This cycle of utility investment ended as early as the 1960s for some utilities and through the early 1980s for others, including Avista.
[59] "Powering a Generation: Power History #3," http://americanhistory.si.edu/powering/past/h2main.htm.

For utilities like Avista that waited to invest in their assets throughout much of the 1990s due to industry uncertainty, the need for capital investment is even greater. The need for utilities to continue investing in new and upgraded facilities is fully supported by Congress' directive to incentivize improvement and expansion of our nation's transmission infrastructure, as defined in the Energy Policy Act of 2005.[60] The Act was focused on reliability as well as development of a robust transmission system. The Act was designed to promote transmission investment through pricing reform, enhance grid reliability, and reduce congestion and system losses in order to provide cost savings for customers.

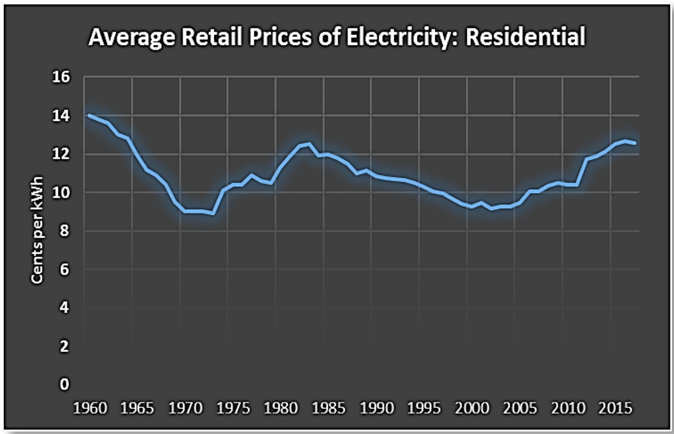

Figure 12. National Residential Cost per kWh
Source: Edison Electric Institute

It is significant to note that all of the benefits just mentioned are provided by transmission, which remains the smallest portion of an electric customer's bill. On average, for the customer, transmission typically comprises 11 to 15% of their bill.[61]

Interestingly, the annual cost per kWh for electricity in the 1960s approached 14 cents (adjusted for inflation), where it is only about 12.5 cents today. Why? Back in 1960, the average customer used about half as much energy as the average customer does today. This indicates that the major driver of grid costs is the *number* of electricity customers, not how much energy they use. In other words, the number of customers connected to the grid determines how many power lines, transformers, meters, and utility staff are needed to safely and reliably deliver electricity. Thus, installing solar panels on your roof reduces load on the system, but it doesn't reduce the cost of connecting you to the grid. Thus as more customers reduce consumption with energy efficiency or other such measures, the cost per kWh is likely to increase for everyone.[62]

Avista rebuilding the Benewah-Moscow 230 kV line across the Palouse

A research study sponsored by T&D World Magazine in 2017 found that transmission-related projects valued at $129.6 billion are in planning or under construction. New projects totaling $98.4 billion are expected to come online during the next five years, including 72

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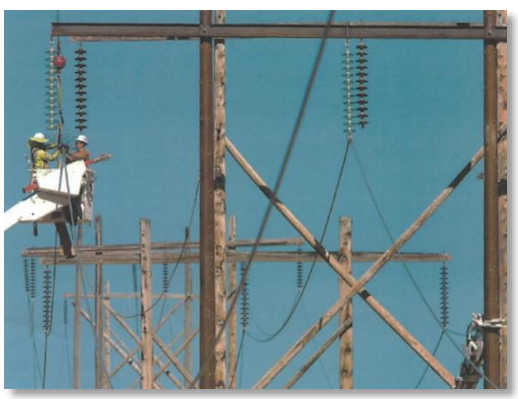
60 The Energy Policy Act of 2005 in full can be found at https://www.energy.gov/sites/prod/files/edg/media/HR6PP%281%29.pdf
61 Matt Pilon, "Federal Regulator Probes Electric Transmission Rates Amid Rising Costs," January 18, 2016, http://www.hartfordbusiness.com/article/20160118/PRINTEDITION/301149893/fed-regulator-probes-electric-transmission-rates-amid-rising-costs
62 "The U.S. Electric Grid's Cost in 2 Charts," Scientific American, April 5, 2017, https://blogs.scientificamerican.com/plugged-in/the-u-s-electric-grids-cost-in-2-charts/ Raw data source: https://www.eia.gov/totalenergy/data/annual/showtext.php?t=ptb0810 and https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_3

major projects with estimated costs of over $100 million each. This study noted that the American Society of Civil Engineers has rated the entire energy infrastructure sector with a grade of D+, which means there is a lot of enhancement work needed in the years to come.[63] Nationwide and for Avista, significant investment in transmission is needed for a variety of reasons including:

- Interconnecting new generation resources and making allowances for plant retirements (especially coal plants).
- Attempting to decrease congestion and increase market efficiency, often in response to NERC reliability requirements.
- Replacing and upgrading aging transmission facilities.
- Supporting public policy goals (specifically renewables and environmental regulations).
- Improving reliability / reducing the possibility of outages (again, in part driven by NERC Standards.)
- Adding new technologies designed to ensure a more flexible, resilient, modern grid and to meet increasing customer expectations for service levels.
- Meeting increasing costs to build new transmission as raw material costs continue to rise, especially on large station equipment such as transformers, which are in high demand due to the large number of transmission projects being built both nationally and globally.

Along with the need to replace aging infrastructure, new NERC regulations regarding reliability are driving expansion and upgrades. In fact, the Brattle Group study found that NERC-related construction will add up to approximately 7,500 circuit miles of transmission nationwide over the next few years.[64] As an example, Pacific Gas & Electric hired a consulting firm to evaluate their 800 circuits and learned that 150 of them, or nearly 20%, required NERC-related mitigation measures.[65]



Rebuilding the Benewah –Moscow 230 kV Line

The cost of building this needed transmission varies significantly from place to place, as many of these costs are dependent upon issues outside of the utility's control such as regional, state and local regulations, environmental issues and concerns, material cost and availability, impacts to neighboring utilities and the grid as a whole.[66]

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[63] Kent Knutson, "Drivers and Challenges for Transmission Investment," T&D World, May 11, 2017, http://www.tdworld.com/transmission/drivers-and-challenges-transmission-investment

[64] "Dynamics and Opportunities in Transmission Development," December 2, 2014, http://www.brattle.com/system/publications/pdfs/000/005/089/original/Dynamics_and_Opportunities_in_Transmission_Development.pdf?1417535596, taken from chart on page 4.

[65] "NERC Mitigation Projects," Burns McDonnell, 2017, http://www.burnsmcd.com/projects/nerc-mitigation-projects

[66] James A. Holtkamp and Mark A. Davidson, "Transmission Siting in the Western United States," 2009, https://www.hollandhart.com/articles/transmission_siting_white_paper_final.pdf. Also see Appendix F "Siting Transmission Lines" on page 89.

Avista's Transmission System

Avista's Transmission System is comprised of 31 lines rated for 230 kV (1 kV = 1,000 volts) and 140 lines rated at 115 kV. These lines are supported by nearly 38,000 poles and structures[67] and span approximately 2,200 circuit miles.[68] Ninety-one percent of this system is single circuit line.[69] These lines range in length from less than a mile to over 86 miles long, and cover wide-ranging geographic territory, from steep mountainous terrain to desert, farmland, and dense urban areas.

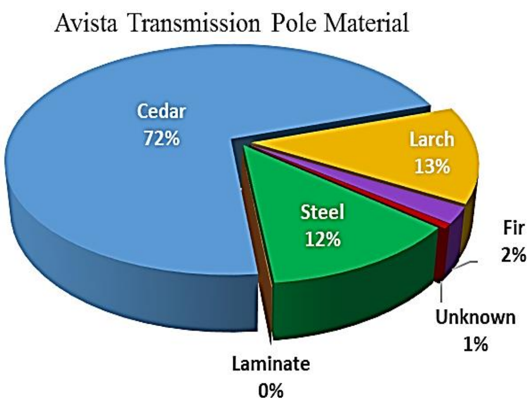


Figure 13. Avista Transmission Pole Types

Avista's poles are primarily butt-treated Western Red Cedar.[70] Wood poles are often being replaced with steel poles as the lines undergo maintenance or replacement. The initial cost of steel poles can be higher,[71] but traditional wood poles have a life-span of approximately 80 years, while steel poles often remain in use for much longer periods than wood.[72] Other factors considered in replacing wood with steel are fire resistance and the savings involved in not having to replace hard-to-reach poles upon failure. Steel poles also tend to strengthen the line, suffer less damage during catastrophic events or from humans or animals, and require less general maintenance.

Asset Category	230 kV	115 kV	Total
Structures	18,246	26,600	44,846
Poles	26,600	9,305	35,905
Air Switches	2	188	190
Conductor (Miles)	686	1,537	2,223
Insulators	22,978	60,202	83,180

Avista's first transmission line was completed between Spokane and Burke, Idaho in 1903. At that time it was the longest high voltage (60 kV) line in the world.[73] The Company rapidly expanded its transmission system beginning about 1905, and by 1915 provided wholesale electricity to local

[67] Poles are single wood structures; structures may be comprised of two or more poles (such as an "H" frame) used together in place of a single pole due to design conditions such as high wind issues, requirements for additional strength when the line turns a corner or makes an angle, or anytime there is a high level of tension on the line.
[68] For a single circuit transmission line, the circuit miles equal the line (or geographic) miles; for a double circuit line the circuit miles would be twice the line miles.
[69] Single circuit has three conductors for the three phases of one circuit (i.e. one line) versus double circuit which has six conductors and two circuits (i.e. two lines). Double circuit is used where greater reliability is needed, to transfer more power over a particular distance, or to utilize one right-of-way.
[70] Western Red Cedar is known to be highly durable and has natural insecticidal properties. "Wood Utility Pole Life Cycle," https://enviroliteracy.org/environment-society/life-cycle-analysis/wood-utility-pole-life-cycle/
[71] For example, a 60 foot wood pole may cost $1850 versus a 60 foot steel pole at $3200, depending upon the market and other factors. Interestingly, the cost of wood versus steel is a controversial subject. For more information see: "Pole Wars: Wood or Steel Argument Continues," http://www.elp.com/articles/print/volume-78/issue-11/departments/technology/pole-wars-wood-or-steel-the-argument-continues.html and "Steel Utility Poles Versus Wood," http://www.steeltimesint.com/contentimages/features/environment.pdf or Electricity Today's "Utility Pole Showdown: Wood vs Steel," https://www.electricity-today.com/overhead-td/the-utility-pole-showdown-wood-vs-steel
[72] Avista's experience (and our climate) indicates that our wood poles last approximately 50 to 60 years, depending upon species and environment, and that steel poles can last up to 150 years. In the industry as a whole, wood poles are expected to last about 30 years; steel can last 80 years or more. For more information on pole lifespan, please see: https://www.galvanizeit.org/about-aga/news/article/take-a-second-look-at-steel-hdg-distribution-poles
[73] Steve Blewett, "A History of The Washington Water Power Company, 1889-1989: Building on a Century of Service," The Washington Water Power Company, 1989

distribution systems scattered as far away as the Cascade Mountains and through most of North Central Idaho. Avista established the first utility interconnection in the Pacific Northwest when it built an interconnection with Pacific Power & Light in 1915.[74]

Avista faces problems similar to most utilities nationwide: aging infrastructure and increasing frequency of extreme weather events. Over half of Avista's transmission lines are over 50 years old and 20% are over 70 years old. Avista's transmission poles face the same situation. Sixty-nine percent of the Company's poles are 50 years old or older (which is over 26,000 poles). Aging poles and cross arm failures have caused almost 40% of Avista's unplanned transmission outages since 2002, with conductor adding another 22% of the outages. Although segments of these lines have been rebuilt and structures and equipment have been replaced, the fact remains that our transmission system is coping with the issues and problems discussed earlier. Many of our assets are at or near the end of their useful life, making them more vulnerable to extreme weather events and increasing the risk of failure.

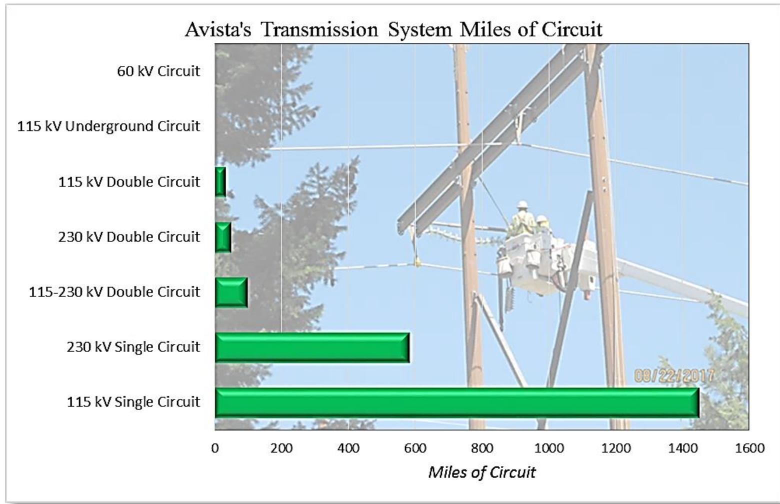


Figure 14. Avista Transmission Miles and Type of Circuit

Often outages caused by disruptions in the high-voltage transmission system are not noticed by customers, because automatic controls and system operators can limit their impact on the distribution system. The transmission system does occasionally experience problems that result in loss of service to customers. For example, overloads in one part of the system can propagate to other parts of the system, like ripples in a pond, overloading substations and leading to loss of electricity to the distribution system. Power service can also be lost if there is an outage on a radially-fed (rather than a redundant) transmission line that serves a remote substation, as mentioned earlier.

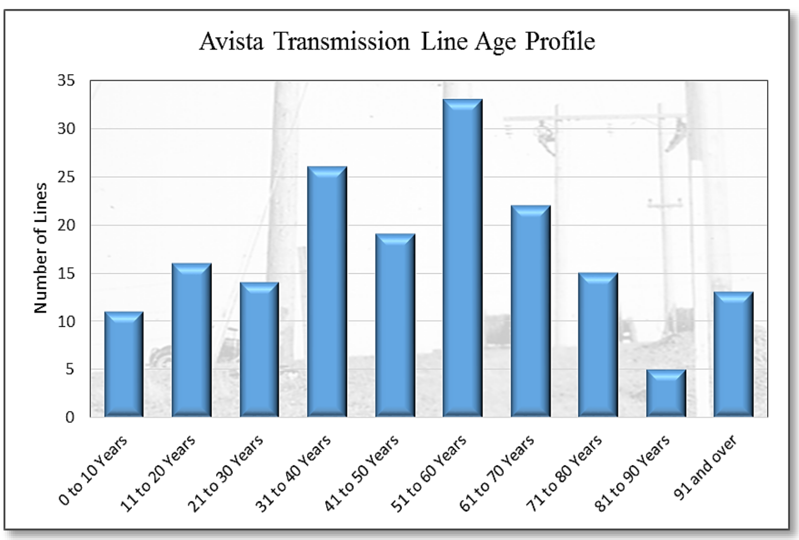


Figure 15. Avista Transmission Line Age

[74] "Washington Water Power/Avista Milestones 1889-2005," http://avanet.avistacorp.com/news/company/eview/2005/documents/WWP_Avista_Milestones.pdf

Transmission line (three arms above) with distribution underbuild below (single arm closest to the ground)

Another transmission reliability concern related to distribution is the use of "underbuild," a common condition across Avista's service territory. In this situation, the utility utilizes a single right-of-way to run two lines. One is a transmission line (which may have more than one circuit like the two transmission circuits on the pole shown in the photograph on the left) with a distribution line attached to the pole at a safe distance below the transmission lines. If the pole is damaged by fire, storm, car-hit-pole, etc., both distribution feeders and transmission facilities can be taken out of service.

Transmission-only line of two circuits with three phases/conductors each on the bottom and a shield wire on top (no underbuild)

Electricity outages disproportionately stem from disruptions on the distribution system,[75] both in terms of the duration and frequency of outages. However, outages on the transmission system while infrequent can result in more widespread major power outages that affect large numbers of customers with significant economic consequences.

Avista's Electric System Reliability

Each year we track and report on how well our system has performed as measured by the number of service interruptions and the duration of the outages experienced by our customers. The Company's annual reliability performance for the years 2004 through 2017 is shown in Figure 16.

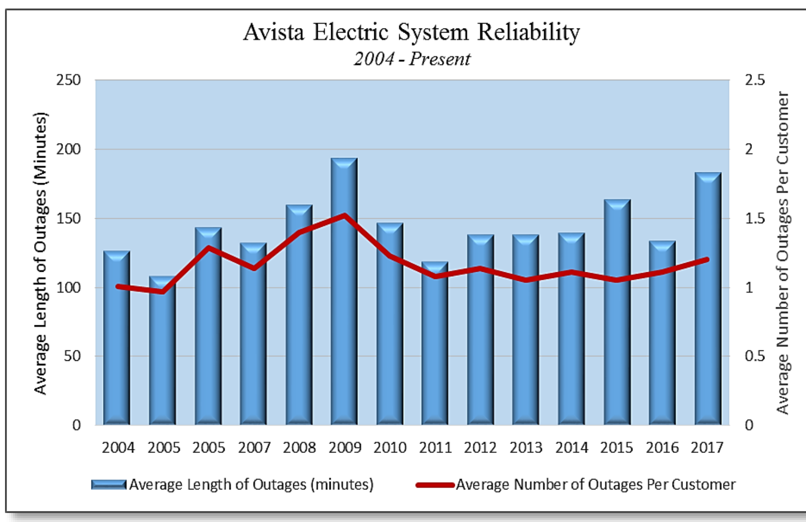


Figure 16. The Average Number & Duration of Avista Electric System Outages

Although our overall reliability trend is generally stable, the year-to-year fluctuation in performance is a common feature of utility electric systems. Outage causes can be quite variable each year and many are largely beyond the control of the utility, such as wind and ice

[75] Over 90 percent of electric power interruptions occur on the distribution system. Source: U.S. Department of Energy, "Ensuring Electricity System Reliability, Security, and Resilience." https://energy.gov/sites/prod/files/2017/01/f34/Chapter%20IV%20Ensuring%20Electricity%20System%20Reliability%2C%20Security%2C%20and%20Resilience.pdf

storms, fires, heavy snowfall, animals, vehicle accidents, etc.[76] In addition to these primary statistics, we report on several other utility-wide measures of reliability, track the geographic areas of greatest reliability concern on our electric system, and develop plans to improve service performance in those areas. Avista is continually looking at ways to improve reliability even though we are providing adequate service according to industry standards.

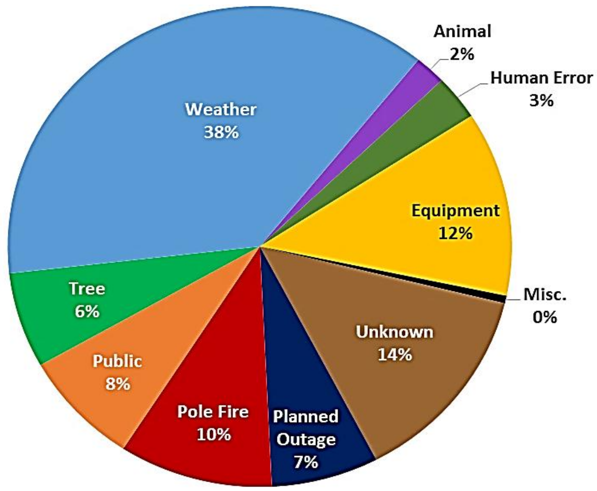


Figure 17. Transmission Outage Causes 2002 - Present

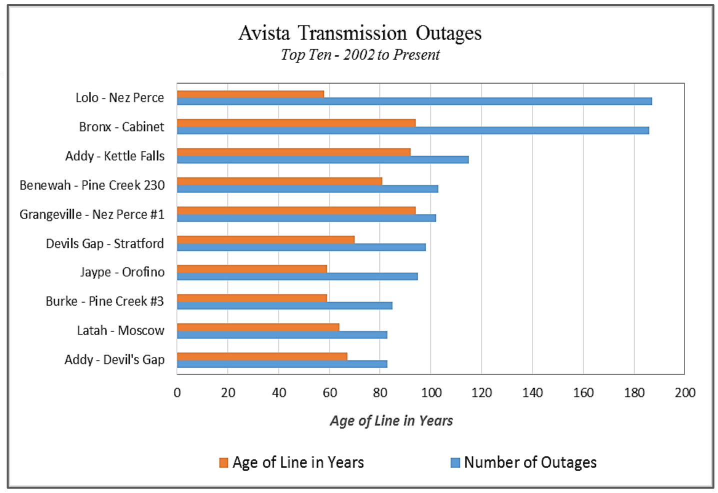
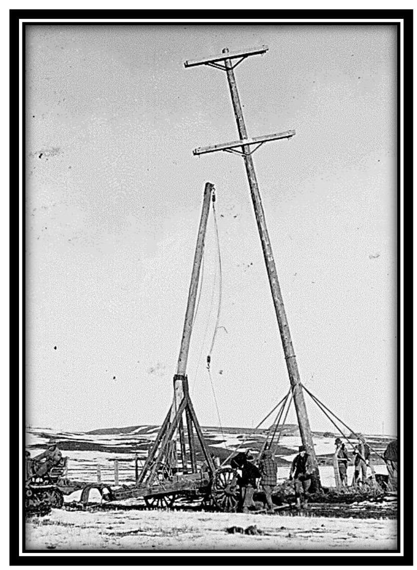


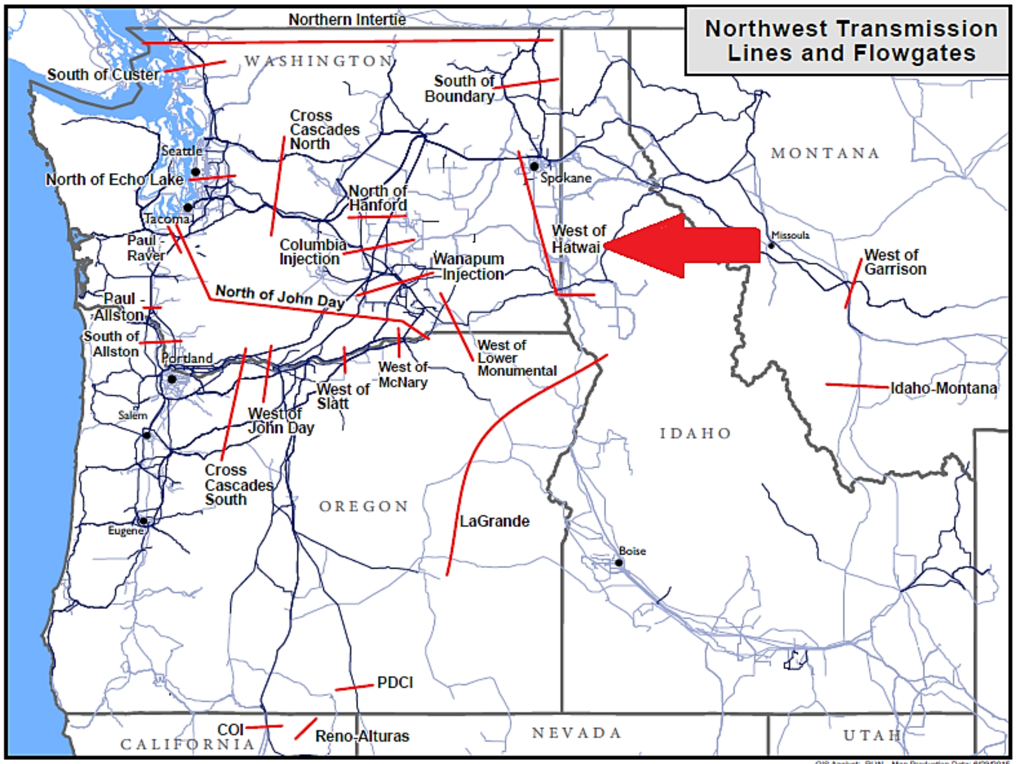
Figure 18. Unplanned Outages & Line Age

Avista Historic Transmission Investments



Beginning in 2004, the Company began rebuilding its aging 230 kV transmission infrastructure. Eighteen transmission lines had been built prior to 1930, another 57 lines were constructed between 1930 and 1960. Not only were these lines feeling their age, but there were congestion issues on Avista's portion of the interconnected system that could affect our neighboring utilities during certain operating conditions. The Company developed a multi-phase plan to address the end-of-life transmission assets in the system and to ensure that the interconnected grid continued to be stable and reliable into the future. This plan, which had a significant impact on Avista's historic expenditures, is described in the next few pages.

[76] The measuring protocol for SAIDI and SAIFI excludes outages caused by very large outage events such as the windstorm of November 2015. These extreme events are referred to a "major event days." Even with these major events excluded, however, we can still experience substantial variability caused by storms or other circumstances that do not qualify as major events.

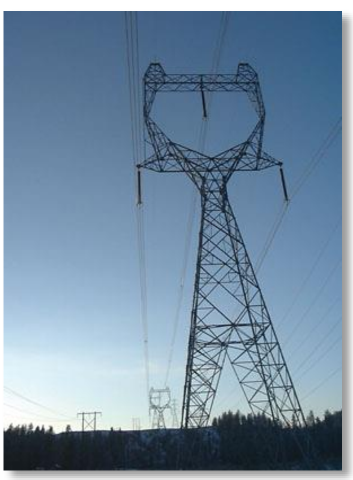


GIS Analyst: RLW Map Production Date: 6/23/2015

Figure 19. West of Hatwai Path (shown with red arrow) [77]

West of Hatwai Project

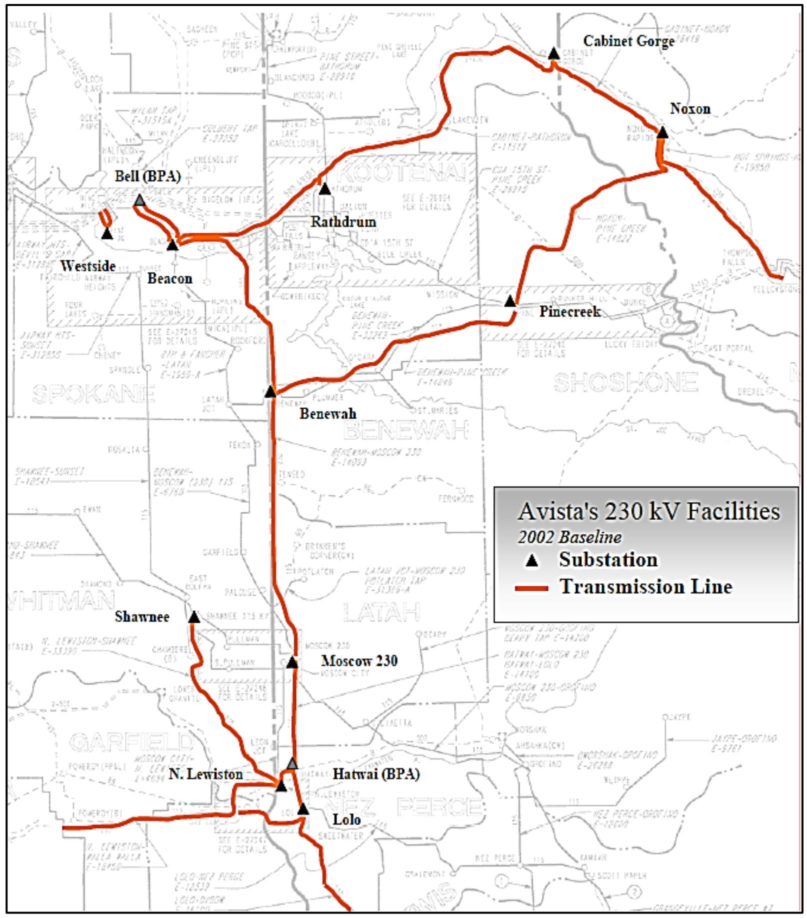
- The West of Hatwai path consists of ten related transmission lines, generally located west and south of Spokane. It is a heavily used path that carries power flowing from Montana to the West Coast and into California. This path is primarily owned by Bonneville Power Administration (BPA), but Avista's transmission system is an integral part of this segment of the interconnected grid. Beginning in the mid-1990s, this path grew increasingly constrained. Initially BPA was able to manage operation of the path through available operating practices of the time, including short-term remedial actions, and customer needs were met while maintaining the reliability of the path. However, in 2001, several major industrial loads shut down in the Pacific Northwest. Two of BPA's large direct service industry (DSI) customers, aluminum smelters located east of the transmission path, closed their facilities. This led to a situation where electricity generated on the east side of the path was no longer serving load located on the east side of the path. That energy was then made available to users west of the path, thus increasing the energy available to flow west on the path. Transmission congestion on the path grew as more energy was available to users West of Hatwai. It became very difficult to reliably balance this change in path flow, and at times led to significant curtailments to users.



BPA's Bell-Coulee 500 kV line, built to help relieve congestion between Grand Coulee Dam and Spokane to the West Coast. (Avista's 230 line visible on the left.)

The problem was particularly acute in the early spring and summer months due to the large amount of power generated by dams east of the path during spring runoff conditions. The amount of power available to move through this area during these months could at times exceed the

[77] Map courtesy of Bonneville Power Administration https://transmission.bpa.gov/Business/Operations/Paths/Flowgate%20Map_2015-06-23.pdf



carrying capacity of the existing transmission lines. By the summer of 2001, all available operating practices to mitigate the capacity limitations of the West of Hatwai transmission path became insufficient as a long-term solution. It was apparent that there was no way to ensure the flow of power while maintaining system reliability.

BPA planned to increase capacity of the path by constructing the Bell-Coulee 500 kV line and making a few other system improvements. However, in order to uprate the path, upgrades were also required on Avista's interconnected 230 kV system. All of these upgrades were reliability based, meaning that in order to increase the path rating, Avista had to ensure capacity under a variety of transmission outage scenarios including lines, substation equipment, and communication failures.

The West of Hatwai Agreement between Avista and BPA was developed in an effort to strengthen the region's transmission system and to deal with this reliability situation. Between 2003 and 2007, Avista added over 100 circuit miles of new 230 kV transmission line. Over 50 miles of line were upgraded with additional capacity. Two new substations were completed and three existing substations were reconstructed. The project included:

(1) **2003**: Hatwai-Lolo 230 kV transmission line upgrade to 800 megawatts (MW).

(2) **2003**: Hatwai-North Lewiston 230 kV transmission line upgrade to 800 MW. Updated the relay and remedial action schemes at this substation.

(3) **2004:** Beacon-Rathdrum 230 kV Line: Reconstructed the 50

Beacon Substation

Dry Creek Capacitor Bank

year old backbone line between Coeur d'Alene and Spokane, increasing transfer capacity from 300 MW to 1600 MW (eventually to 2000 MW) using new high temperature conductor and adding an additional 25 miles of new 230 kV circuit.

(4) **2004**: Rathdrum 230 kV Substation: Upgraded to become Avista's first fully redundant 230 kV substation, relieving a bottleneck between North Idaho and Eastern Washington and significantly increasing reliability in the area by eliminating loss of load when the old main bus would fail. The old bus was replaced with a double bus double circuit breaker configuration,[78] which is fully redundant. Previously bus failures could cause very low voltage in the area leading to significant loss of customer load.

Rathdrum Substation

(5) **2004-2006**: Lewiston-Clarkston Transmission and New Dry Creek 230 kV Substation: Created a 35 mile 230 kV transmission "ring" around Lewiston and Clarkston, relieving congestion during heavy load periods. This ring required the new Dry Creek 230 kV Substation that included a 230/115 kV autotransformer that improved load service and reliability in the Lewiston/Clarkston area. The station also included a 230 kV capacitor bank required for voltage support under certain operating scenarios and contingencies.

Dry Creek Substation

(6) **2005**: New Boulder 230 kV Substation: Installed between Beacon and Rathdrum substations for increased 230 kV reliability and operational flexibility. Also required to increase capacity for the 115 kV system serving the greater Spokane Valley area, as well as transformer capacity support for both the Beacon and Rathdrum Substations. Built fully redundant on the 230 kV side as double breaker double bus configuration.

Constructing Boulder Substation

(7) **2004-2006**: Benewah 230 kV Substation: Rebuilt the 230 kV yard to fully redundant double breaker double bus configuration in order to reliably integrate the Pine Creek, Boulder, Moscow, and (new) Shawnee 230 kV lines. The station also included the installation of a 230 kV capacitor bank required for voltage

[78] A double bus double breaker bus configuration consists of two main buses, each normally energized and electrically connected to each other in such a way that if one is removed from service by a fault or for maintenance, the other breaker continues to function, so there is no interruption to service.

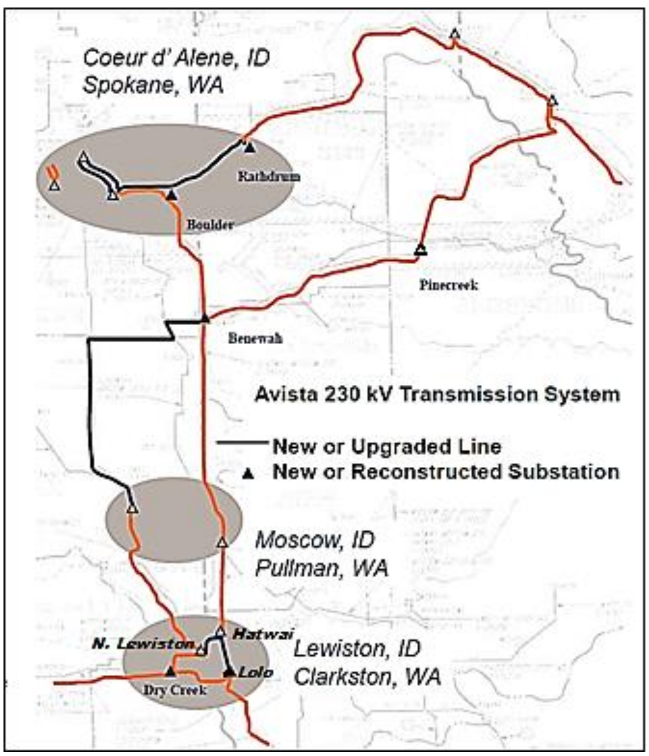
Building Benewah Sub

support under certain operating scenarios and contingencies. Later in 2007-2008, the 230/115 kV transformer and the 115 kV breakers and associated relaying were replaced and upgraded.

Constructing the Palouse 230 kV line

(8) **2006**: Palouse Reinforcement with new Benewah-Shawnee 230 kV Line: Added 60 miles of 230 kV line designed to carry 1,000 megawatts and adding redundancy to a main path between Avista's North (Spokane) and South (Lewiston/Moscow/Pullman) urban areas.

(9) **2006-2009**: Lolo 230 kV Substation: Rebuilt the 230 kV yard to fully redundant double breaker double bus configuration to complete the Lewiston-Clarkston area 230 kV upgrades. This upgrade integrated the 230 kV lines connecting to Dry Creek and Hatwai substations as well as enhanced Avista's interconnection to Idaho Power, improving the station reliability and operational flexibility.



The Avista portion of this project cost approximately $135 million over four years, which included over 100 miles of new 230 kV circuit, 50 miles of upgraded circuit, two new substations, three upgraded substations, upgraded equipment at five of its remaining seven 230 kV substations, 750 MVA of additional 230/115 kV transformation, 400 MVAR of reactive supply,[79] over 200 miles of fiber optic communications cable, and several fully redundant communications systems. This project was implemented to mitigate exceedances of equipment ratings, minimize negative impacts on neighboring utilities, reduce the constraints Avista's system placed on BPA's system, reduce congestion and constraints on other interconnected paths, and allow maximum use of the bulk power marketplace. Resources can now freely move from Montana to the West, increasing resiliency for customers by adding redundancy to key paths and improving reliability to the Western grid in general.

[79] Reactive power is a by-product of the AC power system, measured in Volt Ampere Reactive (MVAR). It helps maintain voltage and is also critical to magnetic-based equipment like large motors. For descriptions of this equipment or definitions of these terms, please see Appendix J (page 97) "Transmission System Equipment" or Appendix Z (page 103) "Transmission Glossary of Terms" at the end of this report.

Overview of Electric Transmission Regulation

In August 2003 North America experienced the worst blackout in American history; 50 million people lost power (over 61,800 megawatts) for up to two days throughout the Northeast and Midwest and into Ontario, Canada. Eleven people died. Investigations revealed practices that varied from utility to utility, human decisions, poor communication, vegetation management issues, and equipment inadequacies all contributed to this outage. The situation prompted Congress to take a hard look at creating consistent standards with penalties for non-compliance. Prior to this, the industry operated under a set of voluntary planning and operating criteria. In 2005 Congress passed The Energy Policy Act, which granted the Federal Energy Regulatory Commission significant new responsibility and authority in overseeing the nation's energy grid. This led to an increasing number of mandatory Reliability Standards that directly impact Avista's operations and associated transmission related expenditures.

Currently electric utilities are highly regulated at the federal and regional levels. The Federal Energy Regulatory Commission (FERC) oversees all electricity transmission and wholesale marketing in the United States. FERC has regulatory authority over both the reliability of Avista's system and the commercial aspects of Avista's wholesale uses of its transmission. FERC has delegated reliability standard development and enforcement to the North American Electric Reliability Corporation (NERC). NERC delegates reliability standard compliance enforcement to regional entities, in Avista's case, the Western Electricity Coordinating Council (WECC) and Peak Reliability. Peak Reliability (Peak), is a Reliability Coordinator, meaning it has the highest level of operational authority within its footprint (the Western Interconnection), monitoring and ensuring the reliable operation of the Western Interconnected electric system. Avista is subject to all operating rules and practices established by Peak Reliability as well as those developed by NERC and FERC. All of these organizations add increasingly complex layers of standards and regulations that are mandatory and enforceable.[80]

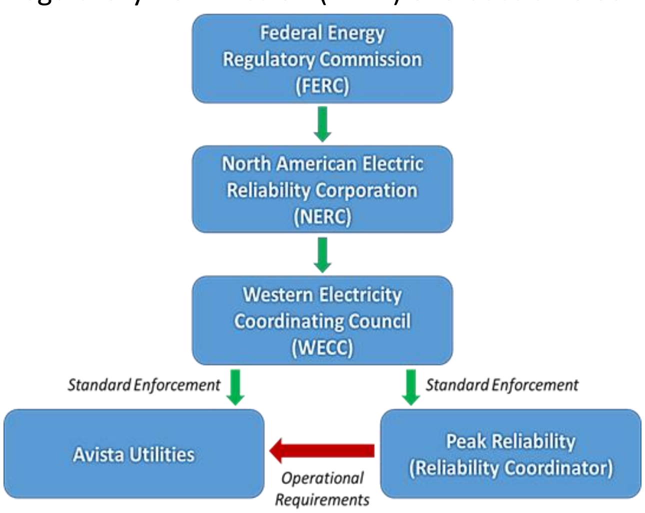


Figure 20. The Basic Levels of Regulation Affecting the Avista Transmission System

Regulation of the utility industry is considered critical, as these companies provide essential services necessary to the well-being of society. In addition to being a critical component in providing essential services to nearly every person in America, utility infrastructure is an integral part of our communities. Transmission and distribution lines and associated equipment exist throughout our surroundings,

[80] For detailed information about the layers of regulation affecting Avista, please see Appendix B "Utility Regulation" beginning on page 68.

creating potential safety risks and hazards to humans and the environment that require oversight. Utilities are also natural monopolies, thus regulation helps protect the public interest by ensuring that prices are fair and just, service is adequate, health, environmental, and safety issues are considered, and that companies are responsive to consumer needs.[81] The complexity of regulation related to utilities continues to evolve as the business itself continues to evolve, with new technologies, increasing threats (specifically related to cyber and physical security) and ever-changing consumer expectations.

These mandatory standards heavily inform Avista's decision-making processes and behaviors. They also help in ensuring that the Company's system is reliable, resilient, and secure. However, decisions that were once based on qualitative risk assessment under a voluntary framework are now made based on deterministic criteria within standards required by law, with non-compliance resulting in substantial financial penalties. This has resulted in changes which influence the Company's capital spending decisions and operating practices to a significant degree.

In addition to the regulating bodies mentioned above, the electric power industry must comply with literally hundreds of national, state and local environmental regulations (including those under the Clean Air and Clean Water Acts). Utilities are governed by laws related to crossing federal lands or affecting unique interests, such as culturally significant sites or endangered species. The National Electrical Safety Code defines the rules for installation of electrical gear, electrical protection, methods and materials and even communications for all electric utilities. The Securities and Exchange Commission and the Commodities Futures Trading Commission enforce regulations related to financial and accounting requirements; anti-trust regulations come from the Department of Justice and the Federal Trade Commission. The Occupational Safety and Health Administration (OSHA) regulates safety standards. State and local authorities and regulators focus on facility siting and zoning, safety regulations, taxes and more; state regulatory commissions determine revenue requirements, allocate costs, set service quality standards and oversee the financial responsibilities of the utility. All of these regulators and regulations have developed over time to ensure that people and equipment stay safe and that the lights stay on. At the same time, required regulations and standards dramatically influence Avista's investment decisions.

For details about the history of regulation and the specific entities regulating Avista and their roles, please see Appendix B, beginning on page 68.

[81] "Electricity Regulation in the US: A Guide," March 2011, The Regulatory Assistance Project. Electric utilities are natural monopolies, thus regulation helps protect the public interest in a variety of ways.

Avista Currently Planned Transmission Investments 2018 - 2022

Over the next five years Avista expects to invest an average of about $75 million annually for its electric transmission system capital expenditures. The expected investment by driver for this period is shown in Figure 21.

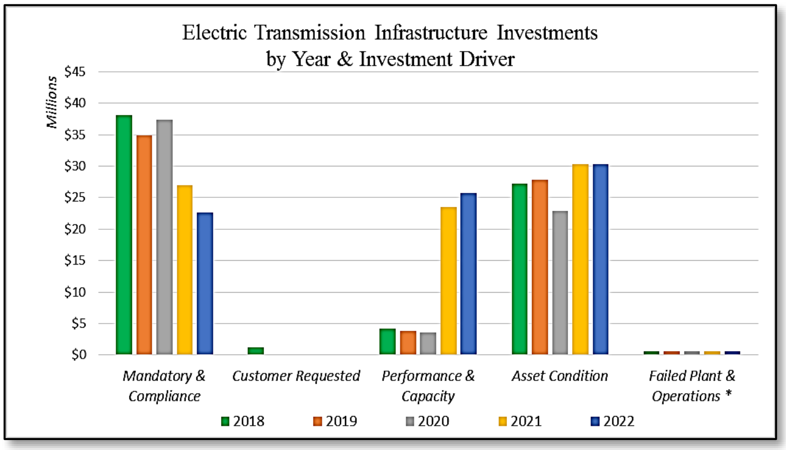


Figure 21. Planned Transmission Capital Expenditures by Investment Driver 2018 -2022 [82]

Avista must continuously invest in its transmission infrastructure in order to maintain safe and reliable service for our customers and to meet mandatory federal reliability standards. These investments replace equipment that has reached the end of its useful life, meet customer requests for interconnection or service enhancement, repair or replace infrastructure that fails, meet our regulatory compliance requirements, ensure the availability of critical equipment when needed, and enhance the capacity or performance of the system to meet Company standards or to serve additional load.

Expected capital expenditures by Driver category are shown below in Table 1. A basic description of the programs in each category follows. Details about specific capital projects and expenditures are available in Appendix A beginning on page 58.

Investment Driver	2018	2019	2020	2021	2022
Mandatory & Compliance	$38,115,000	$34,895,000	$37,365,000	$26,930,000	$22,660,000
Customer Requested	$1,250,000	$0	$0	$0	$0
Performance & Capacity	$4,250,000	$3,800,000	$3,550,000	$23,550,000	$25,700,000
Asset Condition	$27,268,420	$27,843,420	$22,843,420	$30,343,420	$30,343,420
Failed Plant & Operations	$613,314	$631,743	$592,882	$598,720	$598,720
Total	$71,496,734	$67,170,163	$64,351,302	$81,422,140	$79,302,140

Table 1. Planned Capital Expenditures by Investment Driver

[82] Note that the Failed Plant & Operations budget is split between Distribution & Transmission - this chart reflects 18.71% of the total budget, as that has been the average percent used by Transmission for storm expenditures over the past five years.

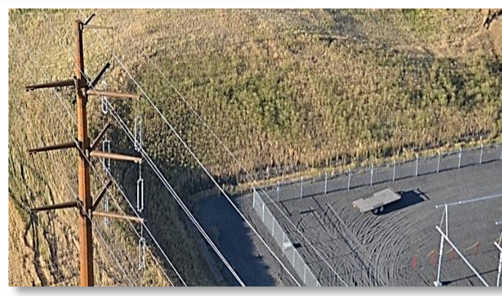
Avista Transmission Capital Programs by Investment Driver

As a way to create more clarity around the particular needs being addressed by Avista's transmission spending, as well as simplifying the organization and understanding of our overall electric spending, the Company has organized the infrastructure investments described in this report by the classification of need or investment driver. The need for investments associated with each investment driver is briefly defined below.

For Avista, expenditures for our transmission system are primarily driven by asset condition (i.e. aging infrastructure) and required compliance; at times these two elements go hand-in-hand, as the West of Hatwai project depicts.

Left: Avista's Community Solar Project

Below: New Transmission & Substation Built in Response to the Palouse Wind Project



Customer Requested

These projects are triggered *by customer requests for new service connections, line extensions, transmission interconnections, transmission capacity, or system reinforcements to serve customers.* In some cases, the Company must construct a distribution substation with an associated transmission line extension in order to meet the requested new load requirements of an industrial or large commercial customer. Other situations may involve a requested transmission interconnection with a neighboring utility or a customer-owned generation project. In the current five year budget period, this category includes an interconnection required to integrate Avista's 20 megawatt solar project being built in Lind, Washington. This project is owned by an independent solar developer who requested interconnection.

Mandatory & Compliance

The 50 year old Beacon-Rathdrum line was rebuilt as part of the West of Hatwai Project

The investments in transmission infrastructure made under this category *are investments driven typically by compliance with laws, rules, and contract requirements that are external to the Company* and typically identified by planning studies and operational issues measured against NERC Reliability Standards. Compliance with these standards became mandatory under federal law in 2007, and failure to comply may result in monetary penalties of up to $1 million per day per infraction. In addition, imbedded within every transmission construction project are environmental compliance costs. These costs vary by project and can cover an array of issues; each project includes numerous requirements for natural and cultural resource protection that didn't exist in the past and that add additional expenses.

NERC standards address transmission planning, operation, and equipment maintenance, requiring utilities to plan and operate their systems to System Operating Limit (SOL) exceedances and reliability risks in real-time. Specifically, the transmission system must be operated so that the next contingency will not result in operating limit exceedances or cascading outages. This requires planning each outage so that the transmission system can absorb the next contingency without any SOL exceedances. Stated differently, the loss of any single facility must not cause any other facility in service to exceed its system operating limit (voltage or capacity ratings) or cause the interconnected transmission grid to operate outside specified reliability limits (voltage and stability limits). This includes circumstances where transmission facilities suffer an outage event, or are purposefully removed from service for maintenance or construction work. The System Operator must determine in advance whether any single outage will result in a violation of a system operating limit, and mitigate for that occurrence prior to such a contingency occurring. This means the system must be designed and built to remain in a reliable state or System Operators must be able to take proactive action to mitigate the expected impacts of a potential contingency. As a result, Avista must ensure that its system can be operated reliably during a variety of seasonal and other outage scenarios. Often projects are developed to provide this system flexibility as required by national standards.

Installing air switches to help protect equipment and isolate faults

Other examples in this category include our contractual obligation to pay 11% of all costs related to Avista's shared ownership of the Colstrip transmission system, as well as general compliance costs for environmental protection and mitigation, leases on tribal lands, contractual obligations, and safety standards.

Performance & Capacity

Transmission investments driven by Performance and Capacity are *a range of investments that address the capability of assets to meet defined performance standards, typically developed by the Company, or to maintain or enhance the performance level of assets based on need or financial analysis.* When the load-carrying capacity of electric facilities is exceeded for any extended period of time, it can stress and damage equipment and lead to equipment failures that can result in customer outages. In the case of substation and transmission facilities, the Company must plan for sufficient capacity in the system to accommodate a planned or forced outage. For example, to take a substation out of service for necessary maintenance, the Company must plan for sufficient capacity in neighboring substations and

connecting lines so the outage does not disrupt service to customers. Investments like Supervisory Control and Data Acquisition (SCADA) systems enable the System Operator to effectively monitor and control the system to ensure proper system performance and operation.

Asset Condition

Investments in transmission infrastructure related to Asset Condition are *to replace assets based on established asset management principles and strategies adopted by the Company, which are designed to optimize the overall lifecycle value of the investment for our customers*. This category includes rebuilds related to aging or end-of-life assets and upgrades related to design, safety, or construction standards. It also includes specific technology upgrades related to interconnected system reliability. The Company closely monitors outages and replaces equipment that is either impacting customer service or is likely to do so. Some equipment is so critical that it cannot be allowed to fail. When this equipment reaches an age when it is close to or at the end of its useful life, the Company preventively replaces it to maintain reliability and acceptable levels of service.

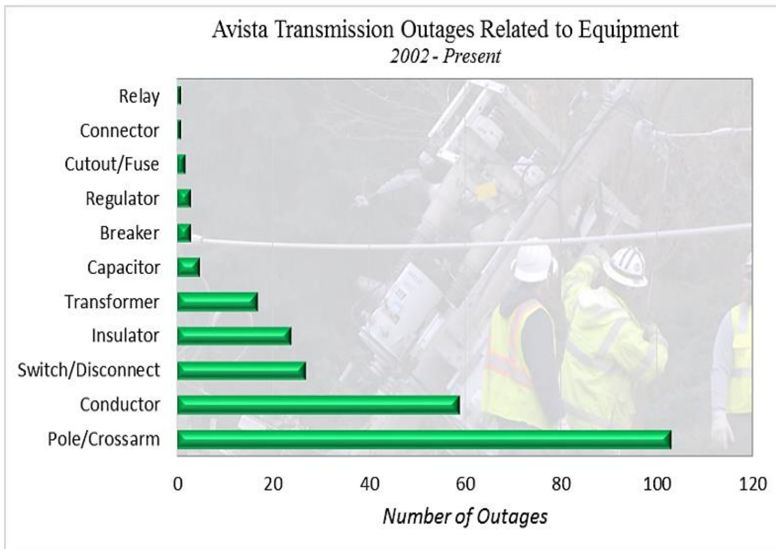


Figure 22. Transmission Equipment Related Outages

Failed Plant & Operations

Transmission investments in this category are *primarily the result of storm damage to the Company's transmission system and the funding needed to support ongoing capital, operations, and maintenance*. Causes of damage to our system include major wind events, lightning, fire, snow and ice, downed trees/vegetation, wildfires, human or animal caused damage, and equipment failure. Routine repairs to the system often require the installation of poles, transformers, crossarms, or overhead conductor. Other failures include the unanticipated loss of assets due to a range of factors including age and condition. Planned spending for this category is shared between Distribution, Substations, and Transmission.

Avista Transmission Operations & Maintenance Investments

Over the next five years Avista expects to invest approximately $2 million annually in maintaining its electric transmission system through five primary programs shown in the pie chart in Figure 23. The expected investment for this period by investment driver is shown in Figure 24.

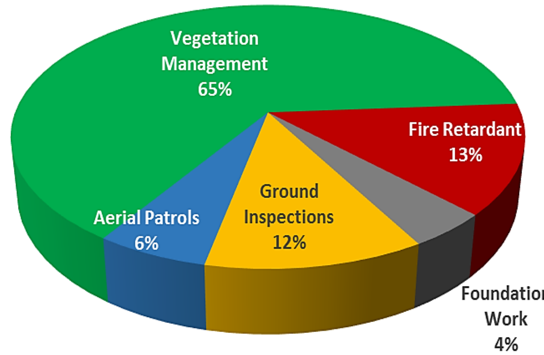


Figure 23. Program Percentage of Transmission O&M Expenditures 2018 - 2022

Avista must continuously invest in its transmission infrastructure to maintain safe and reliable service. Properly planned and executed maintenance helps ensure that our assets will serve customers for the maximum time period and at a high level of effectiveness, reducing outages, and increasing reliability. Aligned with these goals, the Company has five primary Transmission maintenance programs, each of which is described below.

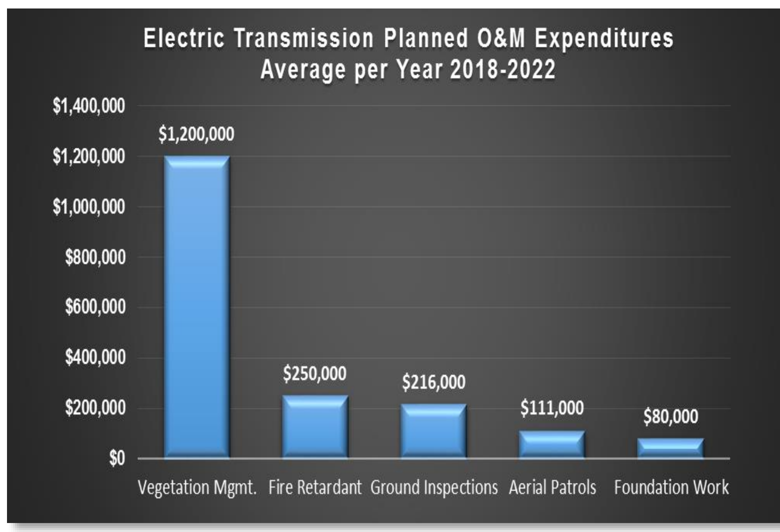


Figure 24. Yearly Average Expected Transmission O&M Expenditures 2018 - 2022

Foundation Work

Power pole foundations are an integral part of the structure. They can comprise up to 30% of the cost of installation.[83] The value of foundations is critical in providing stability for the entire transmission line. Maintenance is of high importance to ensure that these bases remain solid and effective. Avista has two 230 kV lines that have unique steel structures where the interface between the steel sleeve in the foundation and the above-ground structure requires re-grouting after approximately 30 years in order to avoid destructive corrosion. The Company plans to invest $500,000 over the next five years to grouting one of these lines, the Cabinet – Rathdrum 230 kV Line.

[83] Freeman Thompson et al, "Integration of Optimum, High Voltage Transmission Line Foundations," 2009, http://cruxsub.com/core/files/cruxsub/papers/c6988e90fb75df65fa9a4603809f6286.pdf, page 3.




Steps in creating a steel transmission pole foundation

Aerial Inspections

The Avista transmission system covers a large geographical area and includes varied and sometimes inaccessible terrain for traditional vehicles. In order to thoroughly inspect the transmission system, aerial patrols are utilized to provide a thorough and efficient above-ground inspection. These inspections identify significant problems that require attention, such as lightning damage, cracked or sagging crossarms, fire damage, bird nests, hazard trees/vegetation, as well as improper uses of the transmission right-of-way such as dwellings, grain bins, and other types of clearance problems. Winter conditions often create overloading on the lines and structures as a result of snow or ice accumulation or high winds, potentially resulting in component failures. Avista conducts aerial inspections on the lines in spring and early summer in time to find and remedy these types of issues as quickly as possible after they occur and before the summer peak season begins or the equipment goes through another winter.

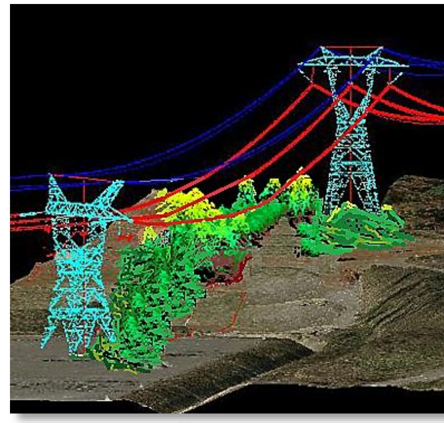
Broken crossarm

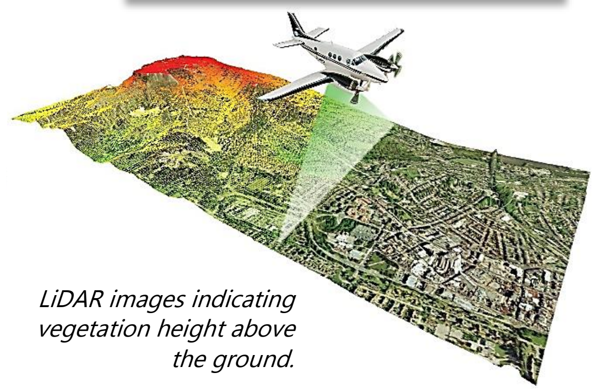
Above: Aerial inspection spots a lightning strike next to a pole

Left: A raptor nest on a crossarm

Patrols are performed by trained and qualified personnel from the Transmission Design Department and typically include local experts such as linemen or area engineers for added perspective. In the event that aerial patrols cannot cover a specific structure or area, or if they are unable to visually inspect to the level desired due to tree growth, fog, wind, construction or other obstacles, a request is made to area managers to have ground crews provide additional inspection. Identified issues are assigned priorities based on safety, risk, criticality to customer service and the integrity of the system, and are closely monitored to ensure that even low priority[84] conditions are tracked and remedied. Area managers are notified of the problems found in their area so they can follow up on mitigation of any identified issue.

One of the tools used in Avista's aerial inspections is LiDAR (Light Detection and Ranging), which consists of a laser, a scanner, and a specialized GPS receiver. This device emits thousands of infrared pulses every second, generating precise, three-dimensional information about the Earth and its surface characteristics. It accurately measures structures, conductors, vegetation, and various features of the ground surface. The data LiDAR provides can be rapidly analyzed to determine where there may be threats to line reliability. It is also a valuable tool when building new lines or rebuilding existing lines, as it provides a very accurate picture of the physical aspects of the area in which the line is or will be located. This makes the design work highly efficient.





LiDAR images indicating vegetation height above the ground.

Avista fully meets NERC Reliability Standard FAC-003-2,[85] which requires that overhead transmission lines be inspected at least once a year, with no more than 18 months between inspections. Actual aerial patrol expenditures average approximately $111,000 per year, with $103,000 set aside over the next five years for this important and NERC required function.

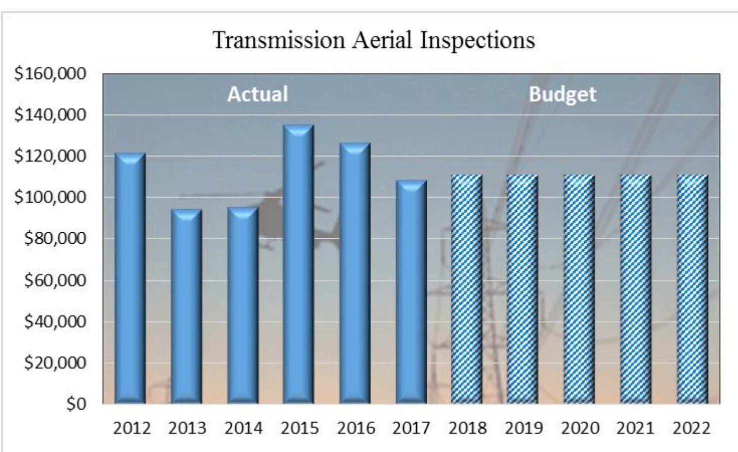


Figure 25. Avista Aerial Inspection O&M Actuals & Budgets

Helicopter flies the Pine Creek – Burke Thompson line

84 Low Priority in this case meaning issues that will not cause any immediate concern, such as a broken bell on an insulator string or a slight lean on the pole.

85 NERC Transmission Vegetation Management Standard FAC-003-2, http://www.nerc.com/pa/Stand/Project%20200707%20Transmission%20Vegetation%20Management/FAC-003-2_White_Paper_2009Sept9.pdf

Ground Inspections

Wood Pole Inspection

Industry studies have indicated that a robust pole inspection and remediation program can add significantly to utility pole service life, up to 30%. Assuming an average wood pole will last 50 years, it is estimated that inspecting and remediating issues when found can add up to an additional 15 years of service life, giving poles closer to 65 years of service.[86] Avista has a highly effective transmission Wood Pole Management inspection program in place to optimize the life, cost, reliability and serviceability of Company poles.

Ground inspection notes "leaners" on the Devils Gap – Line 115 kV Line

Today, approximately 87% of Avista's existing transmission structures are wood (83% of these are cedar).[87] Avista's Transmission Ground Inspections Program tests for decay (the most common cause of wood pole failure is internal and external decay at or near the ground line), as well as other types of damage caused by insects, birds and animals, lightning, fire, mechanical damage, equipment failure such as broken guy wires, grounding or soil issues which can cause poles to lean, or unauthorized attachments. The inspection helps determine which poles must be reinforced or replaced as well as identifying any other work that needs to be done.

Ground inspection finds lightning-damaged pole

In the "field" wood pole inspection program (versus the aerial inspection program), inspectors physically inspect the poles on a 15 year cycle, targeting 2,400 wood transmission poles each year.[88] The transmission lines are prioritized by the length of time since the area was last surveyed and the associated poles were examined. Experience indicates that approximately 15% of the inspected poles will need replacement or reinforcement. This is in great part due to the age of Avista's poles; approximately 45% of the Company's transmission poles and structures are over 50 years old.[89]

[86] The 50 year lifespan is based on industry averages. Avista typically experiences longer lifespans on poles due to the dry climate of the service area. For more information see Jeffrey J. Morrell, Department of Wood Science and Engineering, Oregon State University, "Estimated Service Life of Wood Poles," 2016, http://woodpoles.org/portals/2/documents/TB_ServiceLife.pdf and http://www.steeltimesint.com/contentimages/features/environment.pdf
[87] The lifetime costs of a power pole do not just include the purchase price of the pole, but must take into account the cost of the labor to install the pole and attach the hardware and wires, the expenses related to the truck used to deliver the pole, employee cost for set up, installing and maintaining the pole. If a pole decays quickly or fails, these additional costs are eventually borne by the customer. Avista attempts to keep expenses low by utilizing Western red cedar for our poles, as cedar is widely preferred for utility poles due to their resistance to decay and durability, ease in climbing, strength and endurance. RAM Utilities LLC, "Your Best Pole Purchase," http://www.ramutilities.com/best-new-pole-purchase.html
[88] The 15 year cycle was selected based upon Asset Management analysis. Details available upon request.
[89] Maximo Data Pull 10/23/2017

Avista is currently developing a steel pole inspection program to complement our existing wood pole inspection program. This new program will maximize the efficiency of our existing inspection processes by adding steel pole inspection criteria to current wood pole inspection practices. Previously inspectors would pass by a steel structure due to the lack of information required to develop an inspection specification. When the new program is fully developed, the inspectors will have the proper guidelines to follow. These guidelines will cover the following evaluations: assessment of the environmental conditions that affect the rate of corrosion, structural appraisal of each tower and pole to determine existing corrosion and its effect on the integrity of the structure, any nicks or bends in the metal, foundation condition, and a visual overhead inspection. Once the guidelines are established, Avista's steel poles will be monitored and tracked with the same effectiveness and efficiency that is used in the Company's current Wood Pole Management inspection program.

Steel Pole & Foundation Inspection

Avista's Ground Inspection Program is invaluable in identifying poles needing repair or replacement before they fail and cause outages. Replacing a transmission pole on a planned basis costs approximately $3500 to $4500; experience indicates that replacing a pole on an emergency basis can cost up to three times more.[90] Inspections offer the opportunity to identify problems so they can be repaired on a planned basis before they can reach the point of failure.

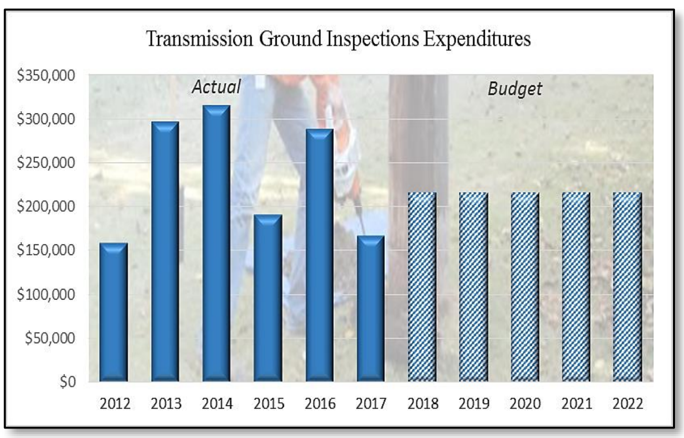


Figure 26. Avista Ground Inspection O&M Actuals & Budgets

Fire Retardant Coatings

After several wildfires caused significant damage to Avista's transmission system, a study was performed in 2008 which determined that systematic coating of poles with fire retardant would be a cost effective means of protecting these investments. The entire 230 kV system has been deemed adequately protected and coating the 115 kV system is currently approximately 37%

Replacing the fire retardant coating on the Lolo-Oxbow 230 kV line

[90] "Transmission Wood Pole Management Model Review," Rodney Pickett, Avista Asset Management.

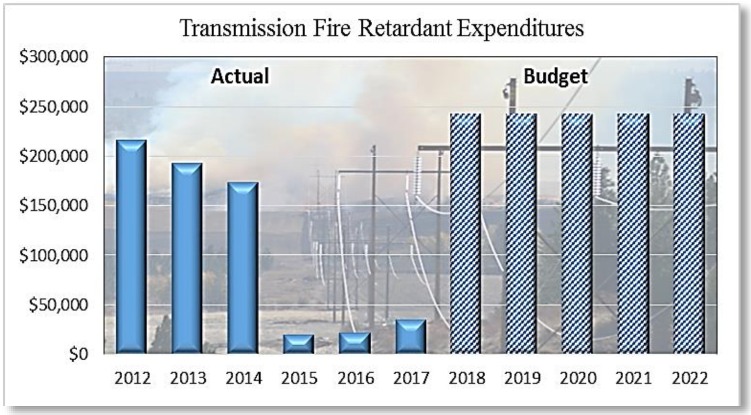


Figure 27. Avista Fire Retardant Expenditures Budgets & Actuals

The Company has experienced the success of this coating in several recent wildfires. Fire burned through the Walla Walla – Wanapum 230 kV line in 2017. As you can see, the fire retardant portion of the pole is safe. Unfortunately this fire burned high enough due to winds that it reached above the protected level.

complete. Coatings are expected to remain effective for 12 years. Targeted areas include those subject to grassland fires and which are in close proximity to railroads.[91] Protective coating is not applied in heavily forested areas as fires in these environments tend to be at such a height that coatings cannot adequately protect the poles.

In the past, the Company has spent an average of $136,000 per year for this program. The current budget of $242,000 per year is based on coating or re-coating 1,000 poles each year. These coatings have been proven to be highly effective industry wide[92] and in Avista's own experience. The cost of coating and the insurance it provides is significantly less than the cost of installing a new pole or structure.

Transmission Vegetation Management

Unfortunate interactions between trees and powerlines have caused numerous outages as well as significant wildfires. Some of the largest outages in the United States and Canada were caused by trees growing, falling, or sagging into powerlines,[93] which led to stringent regulations around issues such as vegetation management practices. In 1990, Avista developed a formal Vegetation Management Program to proactively mitigate vegetation-related outages and risks. Since that time the Company has applied a centralized approach that includes transmission, distribution, and

[91] Trains can emit sparks (carbon sparks from exhaust as well as brakes) and create heat that can ignite. Interestingly, the Milwaukee Road used to have maintenance cars follow a few miles behind trains to spot fires and put them out. Source: Trains Forum "Sparks From Train Starting A Fire?", http://cs.trains.com/trn/f/111/t/46526.aspx and "Wildland Fires Resulting From Railway Operations – A Public Safety Threat," Canadian Interagency Forest Fire Centre, July 24, 2007, http://www.tc.gc.ca/media/documents/rsa-lsf/ciffc.pdf

[92] As an example, in 2015 a fire burned more than 42 square miles in Arizona, burning 220 un-coated poles but failing to destroy even one of the 1,100 poles that had been treated with a fire retardant coating. Osmose, "Protecting Wood Utility Poles from Wildfire," http://www.osmose.com/newsletter-2015-q3-fire-protection

[93] Sagging is especially problematic when lines are heavily loaded and temperatures are high. In addition, once a line fails, the power on that line is diverted onto other lines, potentially overloading them and causing a cascading outage.

high pressure gas lines. This program was initially designed to improve reliability for our customers and to enhance safety for line workers and the general public. When North American Reliability Corporation (NERC) vegetation management regulations became effective in June 2007,[94] the Transmission Vegetation Management Program (TVMP) was formalized with a focus on reliability, compliance, sustainability, and environmental stewardship of Avista's transmission system.[95] Access road maintenance was added to the transmission program in 2009.

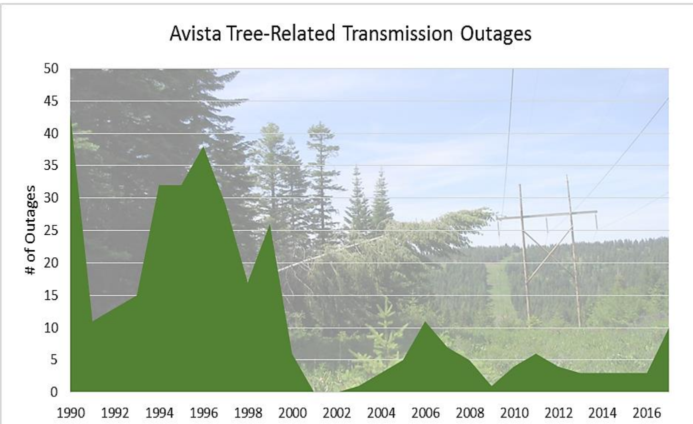


Figure 28. Avista Tree-Related Transmission Outages

Avista's Transmission Vegetation Management Program has been very successful, leading to tree-related outages declining significantly over the past 26 years as can be seen in Figure 28.[96] This is directly attributable to active vegetation management on all transmission rights-of-way. Note that outage data prior to 2000 is inconsistent due to a lack of outage cause categories in data reporting, and because it took a few years for all of the rights-of-way to be cleared once this program was initiated.

Compliance

Avista is in compliance with NERC Transmission Vegetation Standards which are designed to prevent tree-related outages that could lead to cascading outages throughout the interconnection. These standards define minimum vegetation clearance distances based on voltage and elevation and are designed to prevent flashovers caused by vegetation. Transmission owners are required to demonstrate that they considered potential encroachments related to movement of the conductor

NERC Reliability Requirements:

R1 and R2 Prevent Minimum Vegetation Clearance Distance Encroachment **and** sustained outages due to fall-ins and grow-ins from inside the right-of-way on all 200 kV and higher transmission lines and Western Interconnection designated critical paths.

R3 Document maintenance strategies (including prevention techniques).

R4 If vegetation capable of causing a fault is identified, the control center/switching authority must be notified **immediately** with no intentional time delay.

R5 When constrained from performing vegetation work for some reason (such as landowner disputes) evidence must be provided, including that the line was de-energized until the work could be completed.

R6 100% of applicable transmission lines must be inspected/patrolled at least once a year with no more than 18 months between inspections.

R7 100% implementation of annual work plan.

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[94] North American Reliability Corporation Transmission Vegetation Management Standard FAC-003-4, http://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-003-4.pdf

[95] Note that transmission and distribution require different levels of vegetation expertise. Transmission tends to be in forested areas, requiring forestry knowledge and expertise versus distribution, which tends to involve arborist activities such as trimming trees to meet customer requirements.

[96] Outage data management has greatly improved over the past 25 years. The data for this chart was gleaned from System Operator Log and Transmission Outage Reports. The data was hand filtered to capture only tree related outages on lines owned and operated by Avista, and to provide consistency in the outage cause. These outages may or may not have affected Avista customers. Because it has been hand filtered, this is not data that has been previously reported to NERC or the Public Utility Commission. Note that prior to 2007 (FAC-003 implementation) reportable tree related outages on applicable lines had been zero due to lack of outage cause categories.

due to wind, heat, line load, icing, and other factors that could cause sag or sway of the conductor. NERC fines can be assessed for allowing vegetation to get too close to power lines even if it has not caused an outage. Other requirements include annual patrols, 100% implementation of annual work plans (i.e. issues identified), documenting maintenance strategies, and having a process for reporting imminent threat of tree outage. A summary of these requirements is shown in the text box on the previous page.[97]

Budgets and Expenditures

The Washington Utilities and Transportation Commission issued an order in March of 2005 requiring Avista to commit to spending $2.8 million each year on Vegetation Management including both distribution and transmission programs in Washington State.[98] The Idaho Public Utilities Commission issued a similar Order in October of 2004, allowing $1.8 million for Idaho tree trimming.[99]

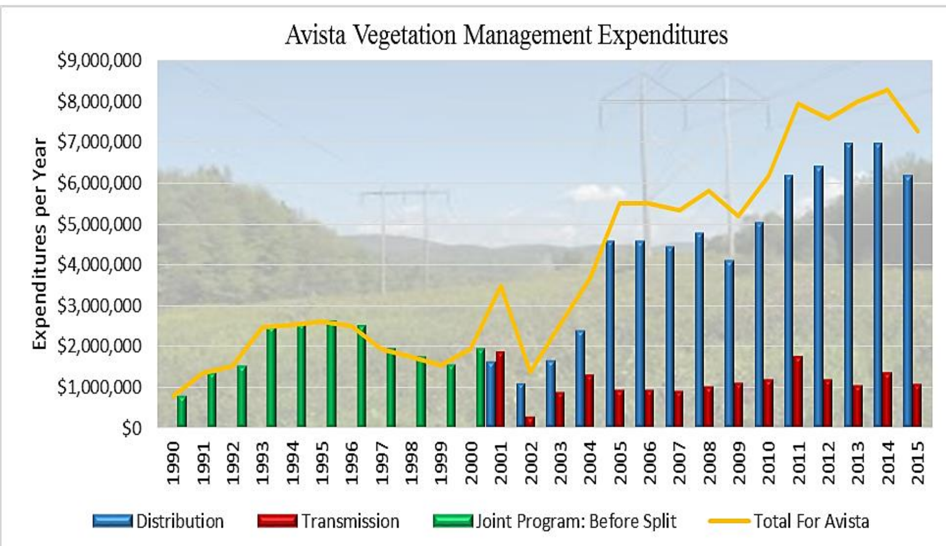

Figure 29. Avista Historic Vegetation Management Expenditures

The transmission and distribution vegetation management programs were split into separate programs in 2001. The transmission piece of Avista's Vegetation Management Program has averaged $1.1 million per year since the split, as shown in Figure 29, with $1.2 million budgeted each year for the next five years as shown in Figure 30 on the next page. The program developed by Avista is cost effective, as it is much less expensive to maintain the rights-of-way than to perform any of the intensive treatments required to initially clear the land around and under transmission lines.

The Transmission Vegetation Management Program (TVMP)

The TVMP is managed by the Transmission System Forester. Avista operates 985 miles of 230 kV and 1,675 miles of 115 kV transmission lines for a total of 32,000 acres of rights-of-way. Lines cross private property, lands owned or managed by federal and state agencies, and tribal nations. Typical land use types are forest, agricultural, channeled scabland, Palouse prairie, and urban, rural and residential areas. Land management activities both on and adjacent to transmission rights-of-way impact

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97 North American Reliability Corporation Transmission Vegetation Management Standard FAC-003-4, http://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-003-4.pdf

98 Washington Utilities and Transportation Commission, Docket Nos. UE-050482 and UG-050483 Order #5, December 21, 2005, page 8. This Order further specified that if this spending falls short in any year, the difference would be spent in a future year or returned to customers via a credit.

99 Idaho Public Utilities Commission Case No. AVU-E-04-1, Order #29602, October 8, 2004.

reliability, safety, access and cost controls. Thus communication and good working relationships with landowners and land managers are an essential part of Avista's program.

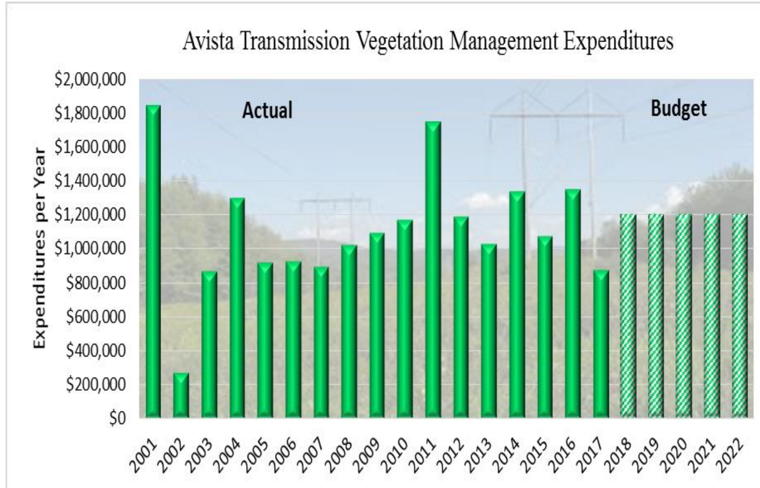
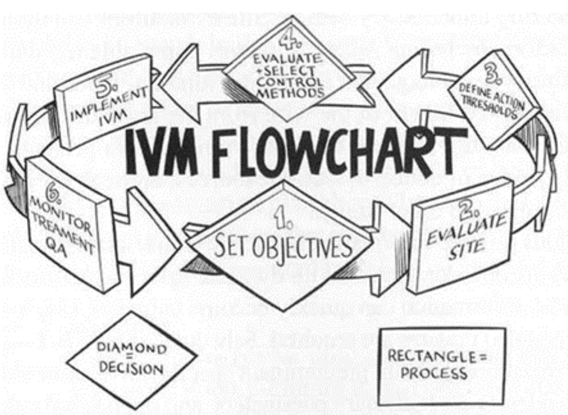


Figure 30. Avista Historic & Projected Vegetation Management Budget

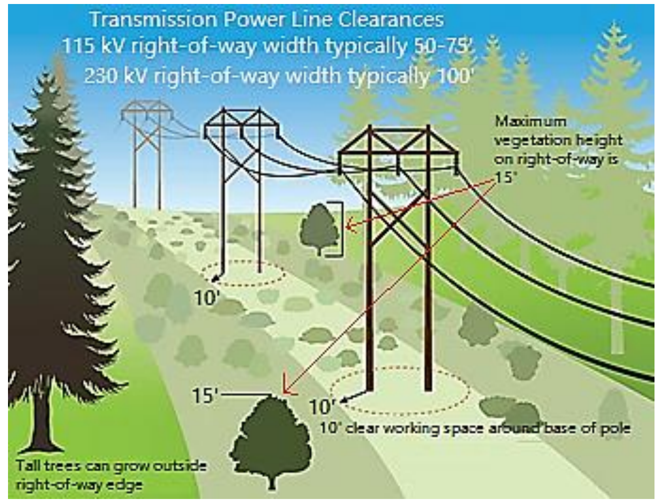
Active management is required on rights-of-way to promote specific vegetation communities[100] that will *not* grow into transmission lines and that *will* promote the long term well-being of the affected environment. Integrated Vegetation Management (IVM) has been adopted as the Avista methodology, as it is both a scientific approach and is considered a best management practice in the industry.[101] Avista's objectives are to use ecological principles and practices to promote dominance of low growing vegetation and exclusion of tall growing plant species that can interfere with electrical wires. Sustainable low growing plant communities provide a variety of environmental benefits, including wildlife and pollinator habitat and soil conservation while protecting the functional right-of-way, access for work on the lines, service reliability, and safety.[102]

Avista's transmission vegetation management is condition-based. It is not a rigid set of activities repeated over time but is governed by a variety of considerations including critical infrastructure lines, voltage, long-term desired state for the right-of-way, landowner goals and activities, budgets, outage patterns and history, construction project schedules, weather conditions, site access, and contractor crew and equipment availability. Standard clearances are determined by voltage level, easement, and line construction type. The System Forester is responsible for managing vegetation-related projects and ensuring that the work is done to meet technical specifications and environmental welfare, handling landowner communications, quality review and inspection of work



100 "Communities" refers to particular combinations of vegetation in an area.
101 Tree Care Industry Association: ANSI A300 (Part 7)-2012 Integrated Vegetation Management (IVM), https://www.tcia.org/TCIA/BUSINESS/ANSI_A300_Standards_/Part_7___Integrated_Vegetation_Management/TCIA/BUSINESS/A300_Standards/Part_7.aspx?hkey=7ea04a09-132b-4b45-a926-6aa043b18465
102 IVM Flowchart courtesy of Randall H. Miller, "Integrated Vegetation Management for Utility Rights-of-Way," 2014. For more information about this, please see Mr. Miller's testimony before the House Natural Resources Committee, http://docs.house.gov/meetings/II/II13/20140507/102191/HHRG-113-II13-Bio-MillerR-20140507.pdf

completed, and maintaining all documentation. A variety of methodologies are available to manage vegetation in transmission rights-of-way. These options are discussed below.



Aerial and Ground Patrols

Patrols are used to evaluate vegetation conditions within the right-of-way, along the edges, and including adjacent land management activities such as logging, land clearing, home construction and road work. Line patrols are completed annually on all 230 kV lines and on other lines considered critical to the Western Interconnection.[103] This is done using helicopter patrols, ground vehicles (including all-terrain vehicles), and hiking. All of the 115 kV lines are also patrolled on a regular basis prioritized by time of last inspection, outages issues, localized insect or disease outbreaks, and land use type. Patrols are used to assess general vegetation conditions on the right-of-way and surrounding area, identify hazard trees, and note future potential growth encroachments. Vegetation treatment or work recommendations are developed from field assessments and either remedied or monitored over time through subsequent patrols.

Treatment

When treatment is required, vegetation conditions, legal requirements and restrictions, and cost effectiveness are all factored in to determining which treatment is the best option. There are also vegetation-related considerations such as species, size, topography, slope, right-of-way width, permits and easements, restrictions, access, and fire risk. Based upon these evaluations, the Company determines which methodology or combination of methods is most effective. Examples are shown below.

Integrated Vegetation Management Treatment Options

- Mechanical Brush Mowing/ Mastication
- Logging
- Manual Hand Cutting
- Selective Herbicide Application
- Hazard Tree Identification & Removal
- Ornamental Tree Pruning
- Vine removal
- Biological controls
- Cultural Controls

Left: Tree caused outage on the Cabinet-Rathdrum line

Below: Cleared right-of-way on the Cabinet – Rathdrum line

[103] This would include any transmission lines above 100 kV that could impact the interconnected grid (other transmission owners/operators) if they went out of service. NERC Bulk Electric System Definition Reference Document, http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf and NERC Transmission Vegetation Management FAC-003-4, http://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-003-4.pdf

Mechanical Brush Mowing/Mastication

- First step in establishing maintained right-of-way
- Useful for high stem density, large contiguous acreage or rural cross-country areas
- Non-selective clearing
- Machine shatters stumps and throws debris chunks up to 300'
- Soil disturbance issues: creates favorable conditions for noxious weed infestation
- Requires good access roads and trails
- Can work up to a 35% slope, but not on side hills
- Limited by rocky talus, steep, or wetland areas
- Uses up to 70 gallons of diesel per 10 hour day
- $1,000- $2,500 per acre

Benewah Pine Creek 230 kV- 1998 prior to mowing

Mower machine with a grinding mower head. This machine has a working height of 11', weighs 80,000 pounds, and has a 6,200 pound mowing head, actuated 270 degrees side to side. The boom reaches out 35' in both directions.

Benewah Pine Creek 230 kV - *First growing season after mowing. Grass, seedlings and greenery growing on the right-of-way*

Logging

- Clearing right-of-way to full easement width and specifications
- Merchantable size timber
- Landowner retains timber rights
- Provides U.S. Forest Service & Bureau of Land Management timber sales
- Requires Safe Practices (Hot Line Hold or Line Clearance)
- Requires heavy equipment: dozer, skidder, loader, haul trucks
- Hand-falling needed for steep terrain
- Sometimes costs more to log and haul than sawmill receipts
- $2,000- $4,000/ acre

115 kV Burke-Pine Creek #4 Right-of-way before logging and mowing full width

Every tree has to be safely controlled as it is felled adjacent to transmission lines. The machine pushes the tree over as the sawyer cuts it off at the base. It must be felled in a way that it can be moved and safely loaded onto trucks to be hauled to the sawmill.

115 kV Burke-Pine Creek #4 after logging and mowing to full width

Manual Hand Cutting

- Used in areas not accessible to mowers:
  - Excessively steep
  - Rocky
  - Wetlands and stream crossings
  - Small acreage
  - Along roadsides
  - Rural residential areas
  - Geographically isolated
- Selective method of clearing
- Heavy manual labor: 3-8 man crews
- Safety concerns of running chainsaw on steep rocky ground
- Logistics include hiking into inaccessible spots and packing all equipment in
- Heavy slash remains on site, increasing fire danger
- Difficult to patrol
- $2,000- $4,000 per acre

Hand clearing work along the Noxon Pine Creek 230 kV ROW. The hill is extremely steep and inaccessible to machinery. Note heavy slash remaining.

Herbicide Application

- Used to maintain right-of-way after mowing, logging, hand-cutting and access road maintenance
- Based on ecological strategies and plant dynamics
- Selective detailed application
- Safety through using specific application methods, product selection, and the use of licensed applicators
- Conversion process to low growing native plant communities
- Minimizes soil disturbance
- Improves wildlife habitat, forage and nesting cover for large and small mammals, songbirds, raptors, amphibians, and pollinator species
- $100- $600 per acre

Trees "brown out" during the same year as the herbicide application. This is an important reason to schedule frequent treatment entries and to target trees less than 6' tall. Over time, as desirable shrubs, ferns, and grasses occupy the site, there is less density of tall growing trees which leads to less herbicide necessary to maintain the right-of-way, translating to less cost.

One year after selective herbicide treatment.

Western pine beetle infestation in Lodge Pole Pines on the Lolo Oxbow 230 kV line

Hazard tree patrol using GPS to collect hazard tree location and other information

Hazard Tree Identification and Mitigation

- Hazard tree definition: "Visibly dead, diseased, dying, damaged, structurally defective, or recently exposed tree that could fall into the conductor"
- Assessment of dead and green trees located both on and off the right-of-way
- Identified during annual aerial and ground patrols, reports from line offices, local reps and other field personnel
- Hazard tree patrols are done by experienced forester
- Hazard trees are cut as soon as practicable after identified.

Ornamental Tree Pruning

- Used sparingly in residential landscape situations
- Communication and negotiation with landowner for tree removal and replacement with low growing tree species is first option
- Requires special equipment
- Requires more frequent attention than rural conditions
- Expensive work due to job set up, communication, crew travel time to each site, and specialty equipment logistics

Backyard 115 kV transmission line with landscape trees directly underneath. Requires pruning every 2- 3 years.

Roadside 115 kV transmission line. Requires aerial lift truck and chipper crew every 3 years to maintain clearance.

Shrub community ten years after mowing and four years after herbicide treatments

Biological Control

- Uses plant biology and ecological principles to adjust plant cover types on the right-of-way
- Uses natural methods to suppress undesirable plant species
- Desired state is sustainable shrub community that inhibits forest species
- Must actively manage through selective cutting and herbicide application to maintain desired state

Left: Six years after mowing. Ferns have an allelopathic effect on conifers, which means they inhibit their growth through chemical interaction via the roots, out-competing conifer seedlings.

Access Roads

Access to the transmission lines is an important component to maintenance and reliability that is often overlooked. Adequately maintaining existing access roads helps protect expensive line trucks and other equipment and aids with outage restoration during major storms and other events. These roads also minimize the disruption and environmental impacts when heavy equipment is needed to perform upgrades or repairs on transmission lines.

Avista's Transmission Vegetation Management Program includes the mandate to maintain access roads and keep them in good drivable condition. This benefits both Avista, agencies, and private landowners, and can minimize impacts to the environment.

Collaboration with University of Idaho

In order to try to maximize the environmental benefits of vegetation management practices, Avista is working with the University of Idaho to evaluate cultural and biological treatments that promote dominance of low-growing shrubs, grasses, and other vegetation that often out-compete tall growing forest trees. This three year research project is providing direct benefits to transmission right-of-way vegetation management objectives and operations.

AVISTA COLLABORATION WITH THE UNIVERSITY OF IDAHO – RESEARCH OBJECTIVES:

1. Evaluate effectiveness of various chemical products and mechanical techniques for controlling undesirable tree species and non-native invasive plants.
2. Assess value of compatible shrub, flowering plants, grass species, and ground cover in inhibiting reestablishment of undesirable trees through cultural and biological controls.
3. Determine timing of treatments necessary to maintain desired vegetation.
4. Develop operational techniques for cultivating shrub communities, including the efficacy of various herbicide formulations, in controlling incompatible plants while restoring native plants from germination available in the soil seed bank.
5. Appraise quality and quantity of plants for pollinator, butterfly and bird habitat.

Summary

The Transmission Vegetation Management Program promotes reliability, safety, and compliance. Rights-of-way are managed for the specific purpose of reducing vegetation-caused line outages. The strategies and methods developed by Avista's program also provide ecological benefits including wildlife habitat, controlling non-native vegetation, and protection for sensitive species, stream courses, soil, and cultural resources. Avista has made a substantial investment in reclaiming and managing the transmission rights-of-way and has built an environmentally sound, cost effective program that will continue to garner benefits in future years. Because of the nature of vegetation management, it is crucial to continue with regular active maintenance activities on the rights-of-way. Through proper management and maintenance, reliability, safety, and compliance will be preserved.

Unplanned Spending

Avista refers to unplanned spending as the cost of dealing with circumstances that cannot be readily predicted. Typical causes in the transmission system are storms, snow and ice loading, or wildfires. The amount spent varies significantly by year as can be seen in Figure 31. This chart shows major storms in December of 2006, July and August of 2014, and the most significant storm in the Company's history in November of 2015. This storm impacted almost half of all Avista customers for up to two weeks. By contrast, we experienced no major weather events in 2016. However, in 2017, wildfires caused significant issues and expenditures. A fire in July and August burned several miles of the Lolo-Oxbow 230 kV line. In August, fire burned through seven miles of Avista's 230 kV Walla Walla – Wanapum line. The damage caused by these two events cost $2.6 million to repair. There were also multiple weather and fire events on the 115 kV lines in 2017 which added another $1.5 million in repairs.

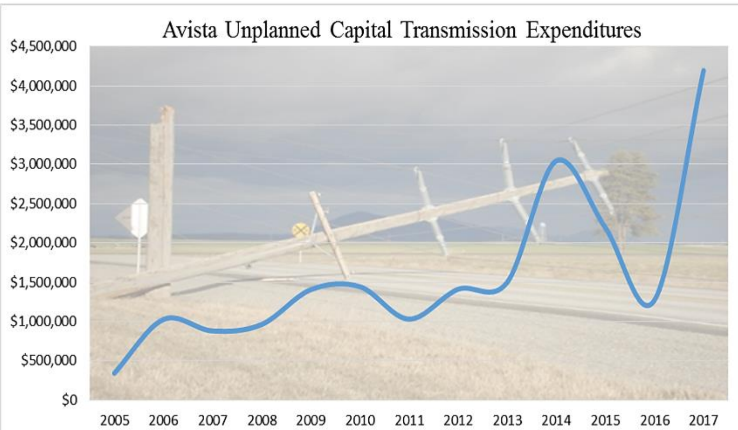


Figure 31. Avista Unplanned Capital Transmission Expenditures

What is left of a transmission structure on the Walla Walla – Wanapum 230 kV line after a wildfire in August 2017.

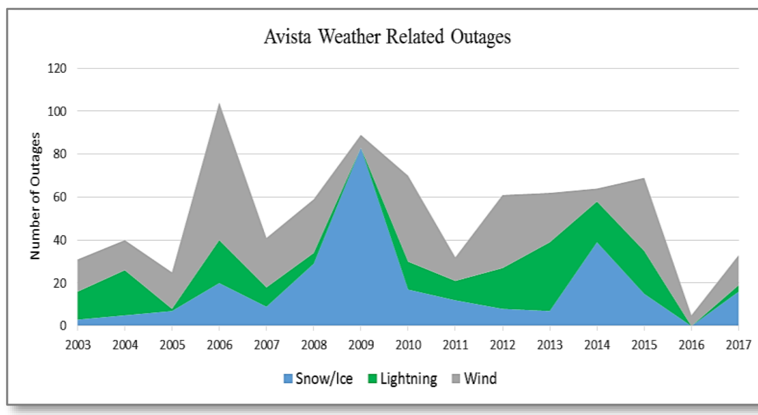


Figure 32. Transmission Weather-Related Outages 2003 - Present

Snow, rain, sleet or hail, Avista linemen are always on the job

Snow/Ice loading causes a line to sag in Spokane

A big windstorm in Rathdrum snapped several transmission poles in the area in 2014

Avista Transmission Organization Functions

Transmission System Operations & Planning

- Real-time Operations (System Operators)
- SCADA/Energy Management Systems/Automated Generation Control Systems
- Operational Planning (12 months and less)
- System Operations Training Program (System Operators and support staff)
- System Operating Procedures (SOP's)
- Outage Management & Coordination
- Emergency Operations
- Short- and Long-Term Planning
- Processes & Procedures
- Regional and National Involvement

Transmission Design & Engineering Standards

- Project Scoping
- Project Budgeting
- Structural and Foundation Design
- Project Management
- Construction Standards
- Compliance
- Construction Management
- Construction Liaison
- Equipment (including Air Switches)
- Vegetation Management
- Pole & Structure Inspection
- Transmission Reinforcement

Transmission Services

- Open Access Transmission Tariff
- Long-Term Transmission Contracts – Negotiation and Administration
- Open Access Same-Time Information System (OASIS)
- Short-Term and Non-Firm Transmission Service
- After-the-Fact Scheduling and Metering Information
- ColumbiaGrid
- Generation Interconnection Process
- Transmission Request Study Process

Appendix A: Avista Capital Project Details

Customer Requested

Lind Solar Project –Avista is in the process of developing a solar facility of up to 20 megawatts.[104] This project was designed to align with State policy goals related to renewable energy. It achieves societal benefits and is responsive to our customers' needs and interests. It also allows Avista to play a unique role in promoting greater customer access to affordable renewable energy. The project will be located just outside of Lind, Washington, adjacent to an existing Avista substation. An independent solar developer will build, operate, and maintain the solar array, which will provide Avista's commercial customers with an opportunity to voluntarily purchase solar energy. The developer requested an interconnection with Avista's transmission system, the costs of which are shown in this business driver category in 2018.

Customer Requested	2018	2019	2020	2021	2022
Lind Solar Project Interconnection	$1,250,000	$0	$0	$0	$0
Total	**$1,250,000**	**$0**	**$0**	**$0**	**$0**

Table 2. Planned Capital Expenditures Based on Customer Requests

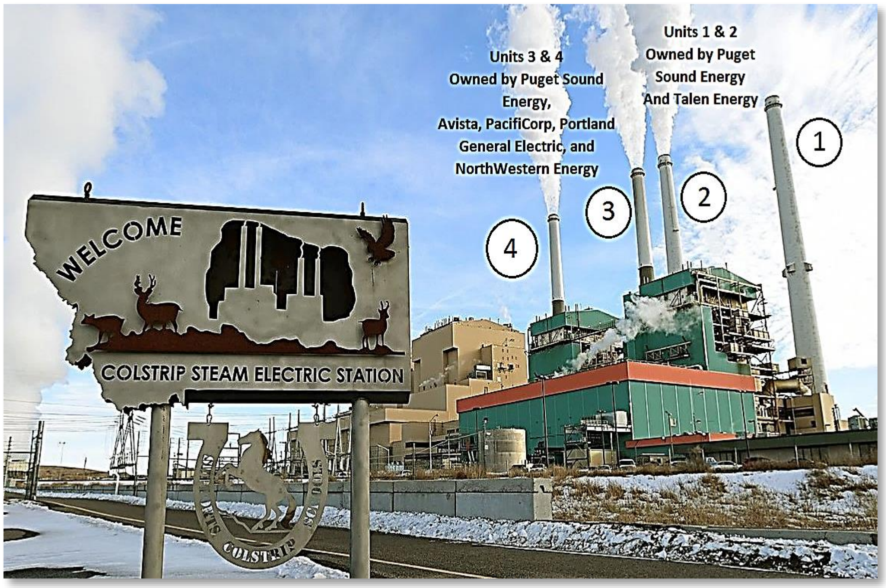
Mandatory & Compliance

As previously described, many of Avista's infrastructure decisions are based upon the requirement to comply with NERC reliability standards. NERC Rules of Procedure are very clear regarding the responsibility and accountability of utilities to be in compliance with Standards and what can happen if they fail to meet the Reliability Standards, including significant fines and penalties. Other planned projects are required by contractual commitments. Ten infrastructure projects required to meet these obligations, described on the following pages.

Colstrip Transmission – Avista owns a 15% share in Colstrip Units 3 & 4 as well as the associated 250 miles of double circuit 500 kV transmission lines that transfer this energy to Avista customers. NorthWestern Energy is the assigned operator of the Colstrip transmission system and facilities. NorthWestern is responsible for actual maintenance. As a joint owner of the Colstrip Transmission System Avista is contractually obligated to pay its commensurate ownership share of all capital improvements, operations, and maintenance costs, as well as any costs associated with compliance with reliability standards. Any failure to comply would cause Avista to be in default of its contractual

Colstrip Transmission

[104] Capacity ratings for utility-scale power stations are usually given in megawatts, which for most technologies means alternating current (AC). However for solar plants this is sometimes expressed in terms of the direct current (DC) peak capacity of the solar array, which for this project would be about 28 megawatts. The 20 megawatts shown for Avista's solar project is in terms of alternating current, which is more consistent with how Avista typically describes generation projects.



Colstrip Ownership

obligations, and the Company would forfeit its rights to the Colstrip system, eliminating the ability to utilize this key asset which is being paid for by our customers.[105] The Company's capital spending for Colstrip since 2011 has averaged $361,000 per year; an average of approximately $416,000 per year is expected in 2018 through 2022. Typical expenditures in the past have included end-of-life replacement of circuit breakers and relays, erosion mitigation around key structures, installation of communication equipment, and hardware/software upgrades related to meeting reliability standards.

Ninth & Central 230 kV Station & Transmission – The Spokane area transmission system is heavily dependent upon the Beacon Substation, which is networked to the Bell Substation as well as eight 115 kV transmission lines. In order to reduce this dependency, create redundancy, enhance customer reliability, and remain in compliance with mandatory standards, Avista is upgrading the infrastructure of the Ninth & Central Substation. The Company is adding new 230 kV infrastructure to accommodate a 230/115 kV auto-transformer and associated circuit breakers, and putting in place additional transformer capacity for the Spokane transmission system. This project will also build eight miles of new transmission lines, utilizing existing 115 kV corridors in a double circuit configuration to fortify the Spokane area transmission system. This project significantly strengthens the electric system in the Spokane area.

Beacon Substation

Ninth & Central Substation

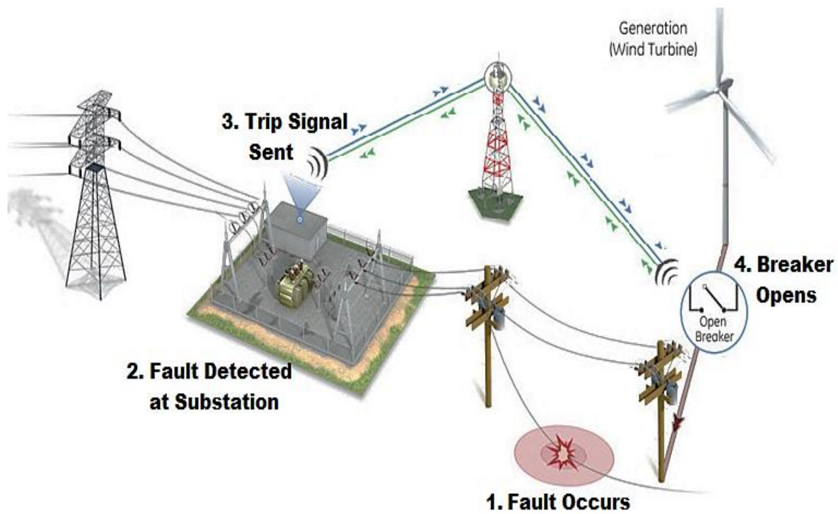
[105] Colstrip Transmission Agreement, https://www.sec.gov/Archives/edgar/data/1127712/000095012300010920/y41907ex10-5_b.txt. Avista has the right to approximately 225 megawatts of Colstrip capacity.

Noxon Switchyard 230 kV Breaker Replacements – The rated ability of the current oil circuit breakers at Noxon Switchyard is inadequate for current requirements. This situation presents safety, reliability, and compliance concerns. The scope of this project involves replacing and upgrading the bus work, including all bus and line disconnect switches. In addition, all oil circuit breakers are being replaced with gas circuit breakers with a sufficient interrupting capability.[106]

Noxon Rapids Dam with Switchyard on the Right

Avista High Voltage Circuit Breaker Undergoing Maintenance

Protection System Upgrade – NERC Reliability Standard PRC-002-2[107] defines the disturbance monitoring and reporting requirements for Bulk Electric System elements.[108] This Standard requires collecting and recording data needed to analyze disturbances. The Standard also requires 50% compliance by 2020 and 100% compliance with these data requirements by 2022. To achieve compliance, Avista is required to upgrade fault recording capability at several substations including: Beacon, Boulder, Rathdrum, Cabinet Gorge, North Lewiston, Lolo, Pine Creek, Shawnee and Westside.



South Region Transmission Voltage Control - Avista's south region 230 kV system, primarily in the Lewiston-Clarkston area, experiences excessively high voltage during light load periods. The voltage levels currently exceed equipment ratings over 35% of the time. Long, lightly loaded transmission lines like those in this region produce large amounts of line charging current[109] which increases system voltage. Currently, there is no

106 Gas circuit breakers have superior insulating and arc extinguishing qualities and can carry higher current levels. They are also non-flammable and chemically stable, require much less maintenance, and are considered more effective at providing the ability to open a circuit to interrupt the flow of electricity, protecting people and equipment.

107 NERC PRC-002-2 "Disturbance Monitoring & Reporting Requirements," http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-002-2&title=Disturbance%20Monitoring%20and%20Reporting%20Requirements&jurisdiction=United%20States

108 NERC defines the Bulk Electric System as any transmission element operated at 100 kV or higher that has the potential to impact the grid.

109 Line charging current is also called reactive power, which is measured in VARs or mega VARs and is required for electrical components, as it allows them to make use of alternative current. Many electronic devices such as computers or televisions only draw current during part of their cycle, and the "leftover" electricity creates reactive load that the electrical system must handle or the voltage stability of the grid can be compromised.

practical way to correct this high voltage issue on the existing 230 kV transmission system without taking lines out of service. Removing lines from service is not practical, as it degrades system performance for the next contingency. In addition, operating equipment outside manufacturer's ratings increases the possibility of equipment failure and presents hazards to personnel. To mitigate this situation, the Company plans to install 50 MVAR shunt reactors[110] at the North Lewiston Substation. This investment provides automatic control, resulting in over-voltages being reduced or eliminated on the 230 kV buses at Dry Creek, Lolo, North Lewiston, Moscow and Shawnee. This project should be complete by the end of 2018.

North Lewiston Reactors help regulate the voltage and reactive power in this area

Saddle Mountain Station – It was identified by Avista System Planning studies and outside entities that the western portion of the Avista's existing system is not meeting NERC performance requirements during heavy load scenarios. The Saddle Mountain project, to be undertaken in two phases, will allow Avista to continue serving Company load in the Big Bend Area near Othello while eliminating pressure on the Grant County Public Utility District system. This problem will be solved by constructing a new 230/115 kV substation where the Walla Walla – Wanapum 230 kV and the Benton – Othello 115 kV transmission lines cross. This new sub will consist of a three-terminal 230 kV double bus double breaker configuration,[111] a 250 MVA 230/115 kV auto-transformer,[112] four 115 kV breakers, rebuilding existing aging 115 kV transmission lines, and building ten miles of new 115 kV transmission. This project will greatly improve the reliability of transmission in the area and remove an existing single point of failure situation which could create widespread outages as well as mitigate potential thermal overloading and voltage issues.

Spokane Valley Transmission Reinforcement Project – This project reinforces transmission in the Spokane Valley area, spurred by load growth in the region as well as compliance with the NERC TPL-

[110] Shunt reactors absorb reactive power, basically consuming reactive VARs, increasing efficiency and stabilizing the system.
[111] A double bus double breaker bus configuration consists of two main buses, each normally energized and electrically connected to each other so that if one is removed from service by a fault or for maintenance, the other breaker continues to function, so there is no interruption to service.
[112] An auto-transformer is used mainly to adjust line voltages or hold them constant, and can step up or step down voltages in the 115 kV and 230 kV range, for example, providing a 115 kV tap from a 230 kV line.

001-4 Reliability Standard.[113] This project includes the construction of a new substation and rebuilding part of the Beacon-Boulder #2 115 kV transmission line. These changes will not only address compliance issues, but will make the transmission system in this urban area more robust, specifically for serving large industrial customers.

Transmission Construction: Reliability – This program covers the transmission rebuild work, line reconductoring, and new construction outlined in the Corrective Action Plan developed under NERC Reliability Standard TPL-001-4.[114] This standard mandates completion of annual system planning assessments studied against specific system conditions and an updated Corrective Action Plan to mitigate the transmission system reliability issues identified. Construction of these facilities will mitigate currently identified reliability issues in compliance with NERC requirements.

Transmission – NERC Low Risk Priority Lines Mitigation - This program was initiated in response to NERC's October 7, 2010, NERC Alert Recommendation to the Industry, titled "Consideration of Actual Field Conditions in Determination of Facility Ratings."[115] It addresses mitigation required on Avista's "Low Risk" 115 kV transmission lines, and brings these lines into compliance with National Electric Safety Code (NESC) minimum clearance values. These safety code requirements have been adopted into the State of Washington's Administrative Code (WAC 296-46B-010).[116] Investments made under this program reconfigure insulator attachments, rebuild existing transmission line structures, or remove earth from beneath transmission lines to mitigate ratings/sag discrepancies found between the designs and actual field conditions.

Placing conductor using a helicopter (above) and by hand (right)

[113] NERC Standard TPL-001-4: http://www.nerc.com/files/tpl-001-4.pdf which requires the Company to avoid load loss and have circuit breakers with sufficient interrupting capability for faults.
[114] NERC Standard Application Guide TPL-001-4, Version 2, http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-001-4_Standard_Application_Guide_endorsed.pdf
[115] NERC Facility Ratings Alert, http://www.nerc.com/pa/rrm/bpsa/Pages/Facility-Ratings-Alert.aspx
[116] Washington State Legislature, WAC-296-46B-101, National Electrical Code legislation, http://app.leg.wa.gov/wac/default.aspx?cite=296-46B-010

Westside 230/115 kV Station "Brownfield Rebuild"[117] – Loads on the existing Westside #1 230/115 kV transformer exceed its facility rating when the #2 transformer is taken out of service. This overloading could potentially cause load shedding, which may impact compliance with NERC TPL-001-4, a Standard which defines system planning performance requirements.[118] This project was developed to replace the existing #1 transformer and upgrade the breakers and buses to a double bus double breaker configuration. These types of transformers are highly specialized, must be custom-ordered, and can take months to arrive. They weigh approximately 170 tons (making transportation costs an issue) and have prices tags of approximately $2,000,000[119] so entail a great deal of planning and preparation as well as installation time.

Above: Westside #1 230/115 kV Transformer
Left: Westside #2 Transformer

Large Power Transformer Procurement Process and Estimated Lead Time – Not Including Installation Time

Mandatory & Compliance	2018	2019	2020	2021	2022
Colstrip Transmission	$470,000	$455,000	$390,000	$405,000	$360,000
Ninth & Central 230kV Station & Transmission	$0	$500,000	$2,700,000	$10,800,000	$16,000,000
Noxon Switchyard 230kV Breaker Replacement	$1,600,000	$0	$0	$0	$0
Protection System Upgrade	$1,395,000	$1,390,000	$1,325,000	$425,000	$300,000
South Region Voltage Control	$500,000	$0	$0	$0	$0
Saddle Mountain 230/115kV Station Phase 1	$6,600,000	$10,800,000	$15,900,000	$0	$0
Saddle Mountain 230/115kV Station Phase 2	$0	$500,000	$1,550,000	$8,700,000	$0
Spokane Valley Transmission Reinforcement Project	$5,250,000	$750,000	$0	$0	$0
Transmission Construction - Compliance	$14,300,000	$12,500,000	$7,500,000	$100,000	$6,000,000
Transmission NERC Low-Risk Priority Lines Mitigation	$1,500,000	$1,500,000	$1,500,000	$0	$0
Westside 230/115kV Station "Brownfield Rebuild"	$6,500,000	$6,500,000	$6,500,000	$6,500,000	$0
Total	**$38,115,000**	**$34,895,000**	**$37,365,000**	**$26,930,000**	**$22,660,000**

Table 3. Planned Capital Expenditures for Mandatory & Compliance

[117] A "Brownfield" project refers to a project that takes place on land that has been occupied by a "permanent" structure at some point, requiring demolishing or renovating a prior structure, versus a "Greenfield" project that will be built in a place where nothing had been built before.
[118] NERC TPL-001-4, http://www.nerc.com/files/tpl-001-4.pdf
[119] U.S. Department of Energy, "Large Power Transformers and the U.S. Electric Grid," 2012, https://www.wecc.biz/Reliability/2014_TEPPC_Transmission_CapCost_Report_B+V.pdf, page 7.

Performance & Capacity

SCADA Build Out Program - This project will complete the installations of Supervisory Control and Data Acquisition (SCADA) and EMS/DMS (Energy Management System/Distribution Management System) capability to all Avista substations. These systems provide full visibility of system conditions and operations, system status indication, and operator control at each substation. SCADA provides automation capability on distribution feeders that allows operators to sectionalize feeders, reducing the number of customers impacted by an outage. This system also provides real time and historical data to the Transmission System Planning, Asset Management, Operations, and Engineering groups to enable efficient, flexible and safe design, planning, and operation of the Company's transmission and distribution systems.

Substation – New Distribution Station Capacity – Adding new substations for load growth and reliability is critical to the long term safe, reliable, and cost-effective operation of the system. As load demands increase and customer expectations related to reliability continue to increase, incremental substation capacity is required to serve those demands. Funding under this category is based on the historical experience of needing to add approximately two new substations to the system per year, or rebuilding/upgrading existing substations to ensure that the system is growing at an adequate pace to maintain the current level of service and reliability. The capital allocated to this program is shared between Transmission, Substations, and Distribution but the entire amount is shown here, as the transmission function creates and manages this program.

Crew setting distribution transformer at the Old Town Sub

Transmission New Construction – Investments made under this program support the addition of new substations due to load growth in a particular area or to reinforce existing substations with new transmission required for increased performance. Investments are typically requested by Transmission Planning or Operations. In addition, funding in this category is used to increase reliability to existing substations by providing a redundant transmission feeds to radially-fed substations, reducing the potential for customer outages. This program is managed through the joint efforts of Avista's Transmission Design & Engineering, Substations, Operations, and Transmission Planning groups.

Performance & Capacity	2018	2019	2020	2021	2022
SCADA Build-Out Program	$2,000,000	$2,000,000	$3,000,000	$5,000,000	$5,000,000
Substation - New Distribution Station Capacity	$2,250,000	$1,800,000	$0	$15,500,000	$9,000,000
Transmission New Construction	$0	$0	$550,000	$3,050,000	$11,700,000
Total	**$4,250,000**	**$3,800,000**	**$3,550,000**	**$23,550,000**	**$25,700,000**

Table 4. Planned Capital Expenditures Based on Performance & Capacity

Asset Condition

This category includes rebuilds related to aging or end-of-life assets and upgrades related to design, safety, or construction standards. It can also include technology upgrades to hardware, software, or other technology-based systems. An example is upgrading the Supervisory Control and Data Acquisition (SCADA) systems used by System Operations personnel in both the primary System Operations Office and the Backup Control Center. This is necessary to ensure that System Operators are able to adequately monitor the electric system without interruption. System Operators perform switching operations, maintain system voltage, respond to abnormal conditions, and maintain constant communication with neighboring systems and regional authorities to assure overall interconnected system reliability using specialized control and communications systems that must be online and available without fail and which is updated as necessary.

Latah-Moscow 115 kV Line, Built in 1924

The Company's Transmission System Asset Management Plan[120] recommends a 30-year replacement period for transmission assets, which requires an investment of $21.1 million per year, split $11.3 million for 115 kV facilities and $9.8 million for 230 kV facilities. Current spending on the replacement of transmission facilities due to asset condition is just under $10 million per year, meaning the Company is currently on a funding level track that will require some transmission assets to operate reliably at an age beyond 60 years.[121]

Substation - Station Rebuilds Program – Replacing and upgrading major substation apparatus and equipment as it approaches end-of-life or becomes obsolete is a routine part of Avista's maintenance strategy. Replacing this equipment before it fails is necessary to maintain the safe and reliable operations of the transmission and distribution systems, as substations are at the heart of these interconnected systems.

The new Pine Creek AutoTransformer

Investments include updating old equipment to meet new safety and construction standards, installing communications systems, and replacing or upgrading primary equipment such as circuit breakers, reclosers, switches, capacitor banks, transformers, and regulators. In addition, supporting equipment like relays, meters, batteries, panel housing, and fences must be replaced periodically to ensure the full functionality and safety of Avista's substations. Please note that capital allocated for this program is shared between Transmission, Substations, and Distribution but the entire amount is shown here as the transmission function creates and manages this program.

[120] 2016 Electric Transmission System Asset Management Plan, http://www.puc.idaho.gov/fileroom/cases/elec/AVU/AVUE1603/company/20160526ROSENTRATER EXHIBIT 7.PDF

[121] Heather Rosentrater testimony, HLR-1T, https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=485&year=2016&docketNumber=160228

Transmission Minor Rebuild - The Company tracks outages with a key focus on recurring outages that require further investigation and, at times, repair or replacement of existing equipment. The Transmission Minor Rebuild category funds transmission structure and air switch replacements based upon the results of the Company's outage tracking, annual wood pole field and aerial patrol inspection programs, and field operations requests regarding the condition of assets. Issues typically addressed include a broken or rotting cross arm, broken or damaged conductor, malfunctioning air switch, or a missing guy line.

Replacing a broken insulator string is part of the Minor Rebuild program.

Transmission Major Rebuild – For significant capital outlays, the Engineering Roundtable prioritizes projects based upon input from Company subject matter experts. This extensive contribution of expertise by function ensures that projects are funded in a manner that maximizes overall customer value and that the system receives the level of maintenance required to insure continued reliable service.

Investments made under this program rebuild existing transmission lines based on overall asset condition as measured by useful life or condition-related outages. Factors such as operational issues, ease of access during outages, and need to add automation or communications equipment are also factored into the prioritization of major transmission capital projects under the guidance of the Engineering Roundtable. The failure to timely replace aging transmission infrastructure on a planned basis would ultimately subject customers to reduced reliability and increased risk of outages. In addition to customer outages, failure to properly invest builds a bow-wave of needed investments in the future.

Working on the Benewah – Moscow 230 kV line

Asset Condition	2018	2019	2020	2021	2022
Substation - Station Rebuilds Program	$13,425,000	$15,000,000	$15,000,000	$15,000,000	$15,000,000
Transmission - Minor Rebuild	$1,843,420	$1,843,420	$1,843,420	$1,843,420	$1,843,420
Transmission Major Rebuild - Asset Condition	$12,000,000	$11,000,000	$6,000,000	$13,500,000	$13,500,000
Total	**$27,268,420**	**$27,843,420**	**$22,843,420**	**$30,343,420**	**$30,343,420**

Table 5. Planned Capital Expenditures Based on Asset Condition

Failed Plant & Operations

The spending in this category is typically related to weather events but can also include more routine failures that happen as assets age and wear out. The amount budgeted is based upon prior years of spending and experience. Most of this spending is applied toward Distribution, which historically experiences the most storm damage expenditures. The amount shown in the table below for Transmission indicates 18% of the Company's total Failed Plant budget, which is the percentage of the storm expenditures utilized by Transmission over the past five years.

Failed Plant & Operations	2018	2019	2020	2021	2022
Electric Storm - Total Distribution and Transmission	$3,278,000	$3,376,500	$3,168,800	$3,200,000	$3,200,000
Electric Storm - Transmission Expected 20% of Total	$655,600	$675,300	$633,760	$640,000	$640,000

Table 6. Planned Capital Expenditures Expected for Failed Plant & Operations

Appendix B: Utility Regulation

Electric utilities are highly regulated at the federal and state levels. The Federal Energy Regulatory Commission (FERC) oversees all electricity transmission and wholesale marketing from the federal level via their enforcement arm, the North American Electric Reliability Corporation (NERC). In addition, the electric power industry must comply with literally hundreds of national, state and local environmental regulations (including those under the Clean Air and Clean Water Acts). They are governed by laws related to crossing federal lands or affecting unique interests, such as culturally significant sites or endangered species, primarily enforced by the U.S. Environmental Protection Agency as well as state environmental entities. The National Electrical Safety Code defines the rules for installation of electrical gear, electrical protection, methods and materials and even communications for all electric utilities.[122] The Securities and Exchange Commission and the Commodities Futures Trading Commission enforce regulations related to financial and accounting requirements; anti-trust regulations come from the Department of Justice and the Federal Trade Commission. The Occupational Safety and Health Administration (OSHA) regulates safety standards. State and local regulators focus on facility siting and zoning, safety regulations, taxes and more; state regulatory commissions determine revenue requirements, allocate costs, set service quality standards and oversee the financial responsibilities of the utility.

Reliability Regulations History

- **1968: NERC is established**
- **1977: New York City Blackout**
- **1996: Western US Blackout**
- **2003: US/Canada Blackout**
- **2005: U.S. Energy Policy Act is passed**
- **2006: FERC certifies NERC as it's official Electric Reliability Organization**
- **2007: NERC standards become mandatory & enforceable**

All of these regulators and regulations have developed over time to ensure the safety of people and equipment and protect the integrity and reliability of the interconnected system.

The History of Regulation

In July of 1977, New York City experienced a blackout that affected most of the city. It started with a lightning strike, but ended with cascading outages due primarily to lack of communications. New York Power Pool's definition of shed load (meaning "immediately") did not match Con Edison's definition of shed load (meaning "using a series of steps"). The system quickly collapsed. This widespread outage caught the attention of the federal government, who instituted voluntary and limited reliability standards to encourage some consistency in operating the national grid (and in communicating with one another).

[122] https://en.wikipedia.org/wiki/National_Electrical_Code and http://www.lni.wa.gov/TradesLicensing/Electrical/LawRulePol/LawsRules/default.asp

Then, in 1996, the nation experienced two more severe blackouts in July and August across the entire Western United States and into Canada and Mexico. These outages, only six weeks apart, were thought to have been primarily caused by excess demand during a very hot summer, as well as vegetation management issues (an overloaded transmission line sagged into a tree). President Clinton directed the Department of Energy to investigate, eventually leading to voluntarily paid fines for reliability violations. Again reliability gained national attention.

Northeast Blackout, August 14, 2003

Then, in August of 2003, North America experienced the worst blackout in American history; 50 million people lost power (over 61,800 megawatts) for up to two days throughout the Northeast and Midwest and into Ontario, Canada. Cost estimates in the U.S. alone ranged from $4 to $10 billion. Eleven people died. Investigations revealed that specific practices (which varied from utility to utility), human decisions, poor communications, vegetation management issues (excessive line sagging into trees again), and equipment inadequacies all contributed to this situation. Communications and technology were so lacking that many of the affected utilities did not even recognize the deteriorating condition of the system until the blackout occurred.

This situation prompted the Federal Energy Regulatory Commission (FERC) to take a hard look at creating consistent standards related to the planning, design, and operation of the national grid and to make such standards *mandatory* and *enforceable* with penalties for non-compliance.[123] In 2005 the United States Congress authorized a bill, The Energy Policy Act of 2005, which granted FERC significant new responsibilities and authority, including the government's blessing on overseeing the reliability of the nation's electric grid and promoting the expansion and modernization of the national transmission system.[124] The Act called for the creation of an Electric Reliability Organization (ERO) to develop and enforce compliance with mandatory reliability standards in the United States.

[123] "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations", U.S.-Canada Power System Outage Task Force, April 2004, https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf
[124] "Energy Policy Act of 2005," Fact Sheet, https://www.ferc.gov/legal/fed-sta/epact-fact-sheet.pdf

In 2006, FERC certified the North American Electric Reliability Corporation (NERC) as the Electric Reliability Organization (ERO) for the United States, with the purpose of insuring the reliability of the North American interconnected electric system. NERC was granted authority to assess, monitor, and enforce mandatory reliability standards, certify bulk power system operators, maintain situational awareness of potential threatening issues, monitor security, investigate and analyze disturbances, and continually update standards as needed.[125]

Note that the terms Bulk Electric System (BES) and Bulk Power System (BPS) are often used interchangeably, but that is incorrect. BES facilities are subject to NERC Standards; BPS may include some facilities that are not subject to NERC Standards.

In 2007, compliance with NERC reliability standards became a legal requirement for utilities with transmission circuits crossing state/province lines in North America, called the "Bulk Electric System" (BES). These requirements cover owners, operators, and users of this system.[126] Today, NERC continues to develop and approve mandatory reliability standards aimed at ensuring Bulk Electric System reliability. These reliability standards can require significant utility capital investments.

Transmission Regulations Governing Avista's Transmission System

FERC has regulatory authority over both the reliability and commercial aspects of Avista's transmission system. The commercial aspects relate to Avista's Open Access Transmission Tariff (OATT).[127] FERC has delegated reliability standard development and enforcement to the Electric Reliability Organization (ERO), a role that is fulfilled by the North American Electric Reliability Corporation (NERC). NERC delegates reliability standard compliance enforcement to Regional Entities, assuming they will have expertise regarding their particular areas of the country. In Avista's case, this is the Western Electricity Coordinating Council (WECC) that oversees the Western Interconnection. All of these entities will be discussed in further detail in later sections of this Appendix.

How do FERC and NERC Fit Together?

- FERC generates an order regarding a reliability issue
- NERC (delegated authority, but not a governmental agency) begins industry-driven process to develop reliability standards in addressing the FERC order(s)
- FERC has approval or denial authority over reliability standards and enforcement actions proposed by NERC

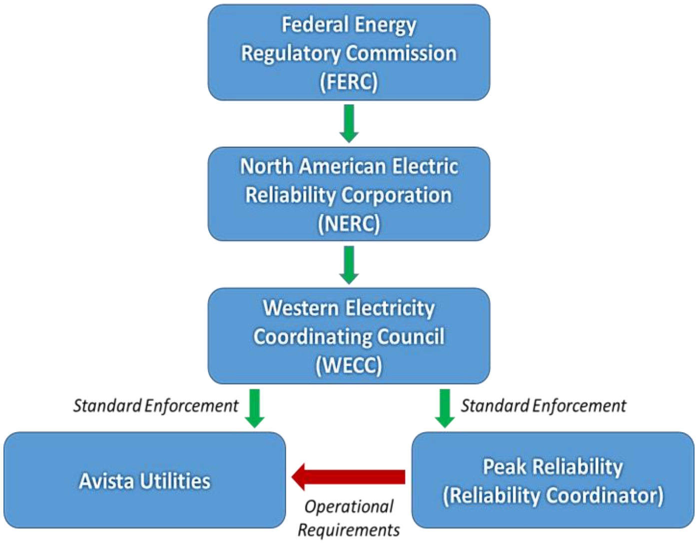
Reliability standards can be developed nationally through the NERC process, or regionally within the Regional Entity (WECC). In either case, NERC's Board of Trustees must approve the reliability standard. After NERC approves a reliability standard, it moves to FERC, where FERC may either approve or remand the standard for further

[125] For more details, see: http://www.nerc.com/AboutNERC/keyplayers/Documents/ERO_Enterprise_Operating_Model_Feb2014.pdf

[126] NERC Glossary Bulk-Power System: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. For more details see: http://www.nerc.com/mwg-internal/de5fs23hu73ds/progress?id=QUcpT-pcF40aV6O5eTSOC48hELZTfcU6WASkXdu3AFU,&dl

[127] The OATT is a tariff that helps insure that all transmission owners and customers have fair and open access to the grid, includes rights and responsibilities of these groups, cost recovery and allocations and system planning requirements. The history of OATT: https://www.ferc.gov/industries/electric/indus-act/oatt-reform/history.asp and https://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp. See page 84 for information about Open Access Same-Time Information System (OASIS).

development. Once FERC has approved the reliability standard, it becomes mandatory and enforceable.



The Basic Levels of Regulation Affecting the Avista Transmission System

Under these reliability standards, a Reliability Coordinator (RC) is assigned responsibility for the reliable operation of the facilities that make up their portion of the interconnected system. WECC designated Peak Reliability to be the Reliability Coordinator for the Western Interconnection. The RC has the authority and responsibility to set operating rules that maintain system reliability for the Western Interconnection. One example of this is the Peak Reliability System Operating Limits Methodology. This document defines how Transmission Operators, such as Avista, must rate their facilities and operate their systems to maintain system reliability. Whereas in the past, Transmission Operators like Avista could define their own System Operating Limits based on a multitude of criteria, Peak's methodology ensures consistency with all of the Transmission Operators within its jurisdiction. Each Reliability Coordinator has complete operational authority within its designated area, and its operating instructions are fully enforceable.

The primary regulatory bodies are described in more detail below.

Federal Energy Regulatory Commission (FERC)

The FERC is an independent U.S. government agency organized under the Department of Energy. Its mandate is to "protect the public and energy customers, ensuring that regulated energy companies are acting within the law."[128] This agency regulates the overall reliability of the electric grid, interstate transmission of electricity and natural gas, and the wholesale sale of electricity and related energy markets. It also licenses hydroelectric power plants and approves construction of interstate gas pipelines, storage facilities and liquefied natural gas terminals. Note that FERC does not regulate the construction of electrical transmission and distribution systems or generation, but has regulatory jurisdiction over all wholesale uses of these assets that are owned and operated by public utilities as defined under the Federal Power Act.[129] FERC delegated authority to the North American Electrical Reliability Corporation (NERC) as the Electric Reliability Organization, responsible for overseeing the security and reliability of the bulk power system in North America subject to FERC oversight. Although NERC covers most of North America, FERC jurisdiction is limited to the U.S.

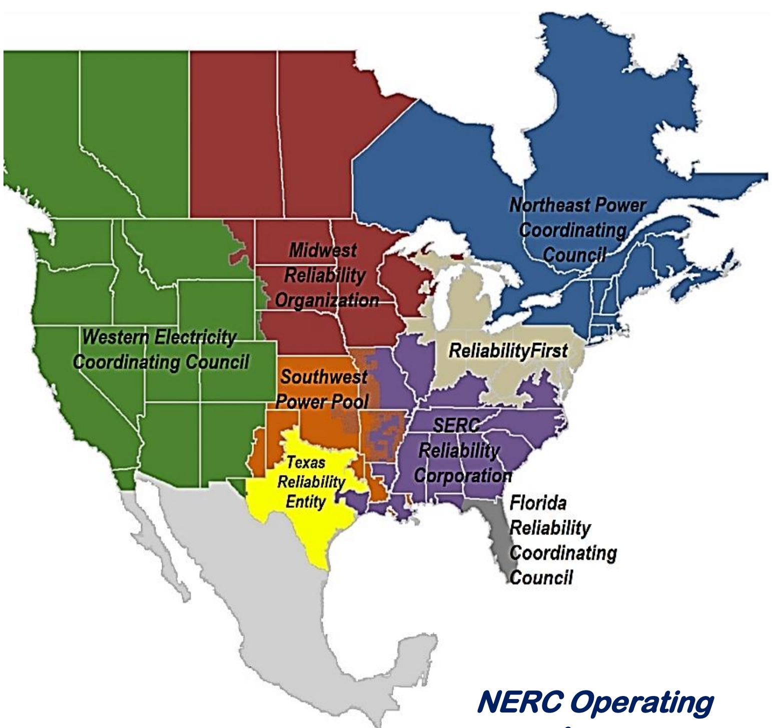
[128] "What is FERC?" https://www.ferc.gov/students/whatisferc.asp

[129] Definition of a "public utility" is any person or company that owns or operates facilities used for the transmission of electrical energy in interstate commerce, per Lawrence R. Greenfield, "An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities in the United States," Federal Energy Regulatory Commission, December 2010, https://www.ferc.gov/about/ferc-does/ferc101.pdf, page 11.

North American Electric Reliability Corporation (NERC)

The NERC is the electric utility industry's primary point of contact with the U.S. government. NERC is responsible for developing and enforcing standards related to the interconnected grid, with jurisdiction over users, owners, and operators serving over 334 million electric customers in North America. NERC's primary job is to ensure the reliability of the national grid - that there is a continuous supply of electricity at the proper voltage and frequency. It continually assesses the adequacy of the national grid, certifies that critical infrastructure is adequately planned, maintained and operated, audits owners, and warrants that operators and users are adequately prepared to handle routine as well as unexpected events. In addition, it educates and trains industry personnel. NERC's purview spans the continental United States, much of Canada and parts of Mexico, although NERC has no enforcement authority outside of the United States other than that created by agreement.

NERC's role in Canada is similar to its role in the United States. While the process for approving NERC Reliability Standards varies in the different Canadian jurisdictions, most of the provinces have agreed that NERC Standards—in some cases modified to reflect the jurisdictions' reliability regimes—are mandatory and enforceable in the provinces of Ontario, New Brunswick, Alberta, British Columbia, Saskatchewan, Manitoba, Nova Scotia and Quebec. Enforcement programs vary among the provinces, with provincial regulators having ultimate authority for monitoring and enforcing compliance in most provinces. Authority over electricity generation and transmission in Canada rests primarily with provincial governments. However, all have recognized NERC as the electric reliability standards-setting organization and have committed to supporting NERC in its standards-setting and oversight role in North America.[130]



NERC Operating Areas

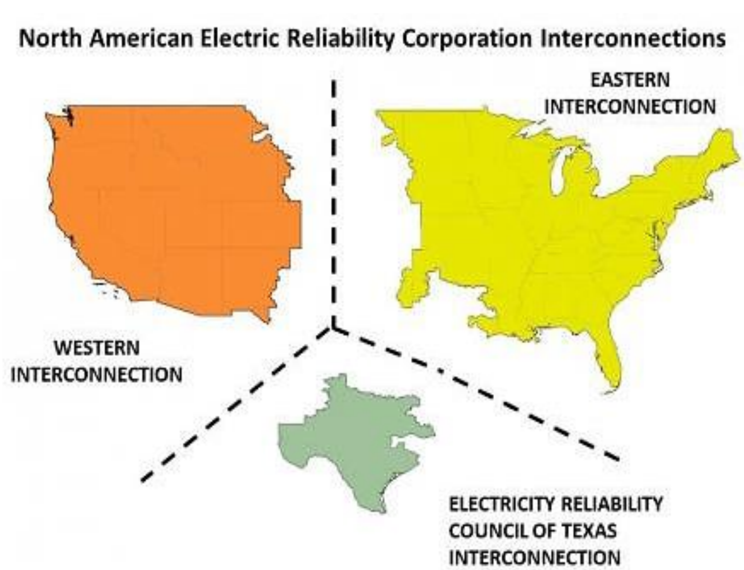
In Mexico, the Mexican Federal Regulatory Commission, Comisión Reguladora de Energia (CRE) and the Mexico System Operator, Centro Nacional de Control de Energía (CENACE) which manages the operation and planning of the Mexico

[130] NERC, http://www.nerc.com/AboutNERC/keyplayers/Pages/Canada.aspx. For detailed information about each Canadian Province's agreement with NERC: http://www.nerc.com/AboutNERC/keyplayers/Documents/Canadian%20Provincial%20Summaries%20of%20Standard-Making%20and%20Enforcement%20Functions%20with%20US%20Comparators%20(2).pdf. Currently Newfoundland and Labrador are connected to each other but not to the rest of Canada. Upon completion of a high voltage DC line to Nova Scotia currently under construction, they will determine whether to agree to NERC Standards.

national power grid, have adopted at least ten of NERC's primary Reliability Standards.[131] Though the two countries have worked together on this in the past and Mexico has voluntarily followed NERC guidelines, a memorandum of understanding between the three agencies was signed on March 8, 2017, which recognizes the growing interconnections between Mexico and the United States and establishes a collaborative mechanism for identification, assessment and prevention of reliability risks to strengthen grid security, resiliency and reliability of grid across North America.

NERC defines the Bulk Electric System (BES) as the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, operated at voltages of 100 kV or higher (but not including radial transmission serving only one load with one transmission source).[132] It defines a ***reliable*** BES as one that can meet the electricity needs of end-use customers even when unexpected equipment failures or conditions reduce the amount of available electricity on the system. That entails both *adequacy* (sufficient resources) and *security* (resiliency). Since NERC has regulatory authority over the entire North American grid, it developed standards to ensure that the entire interconnected system is reliable according to its definition of this term, and that those standards are enforced nationwide and industry-wide.

In order to do all of this, NERC develops standards designed to promote consistency in grid planning and operations. They set standards for resource and load balancing, emergency preparedness, communications, facilities design and maintenance, and coordination with neighboring utilities. NERC Reliability Standards are developed using an industry-driven process; stakeholders actively participate to ensure that all perspectives are considered.[133]



United States Primary Grids

NERC reliability standards are designed so that the grid is planned and operated such that no credible contingency can create a cascading outage or uncontrolled blackout. They also address emergency operating conditions, such as system restoration from a widespread outage, facility rating methodologies, and personnel training requirements.

In order to incorporate all of the national and international issues and differences most efficiently, NERC created several layers of regulation and oversight. The nation

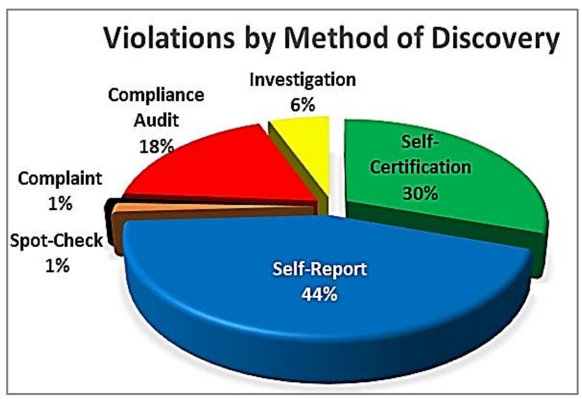
[131] Baja California Norte, Mexico, is part of the WECC but only by agreement – WECC helps them monitor their compliance with certain standards but has no enforcement authority. WECC offers compliance monitoring for CFE in the portion of Baja California Norte that is interconnected to California.
[132] North American Electric Reliability Corporation Memorandum, April 10, 2012, http://www.nerc.com/files/final_bes_vs%20_bps_memo_20120410.pdf
[133] "NERC Roles & Responsibilities," http://www.nerc.com/pa/Stand/Resources/Documents/DraftingTeam_Roles_and_Responsibilities.pdf

is broken into three primary grids: Eastern, Western, and Texas, which operate largely independent of each other and with limited transfers of power between them.[134] All of the electric utilities within each of these three interconnections are tied together during normal operating conditions and operate at a synchronized frequency of 60 Hertz. Although all of the North American interconnections operate at the same average frequency, the three individual interconnections are not in synch with one another and therefore cannot be directly connected through AC transmission lines. These three primary entities[135] can be tied to each other via high-voltage direct current (DC) transmission lines or with variable-frequency transformers,[136] which permit a controlled flow of energy while functionally isolating them from each other.[137]

NERC REGIONAL OPERATING ENTITIES

- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- ReliabilityFirst (RF)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool Inc. (SPP RE)
- Texas Reliability Entity (Texas RE)
- Western Electricity Coordinating Council (WECC)

These three areas are divided into eight **Regional Operating Entities** (shown in the text box on the left), each of whom are responsible for ensuring that their area of the grid is reliable, adequate, and secure. These entities enforce all NERC standards and, in addition, may develop region-specific reliability standards based on local and regional technical expertise and system characteristics. NERC believes that, given the "highly technical and intricate complexities of planning and operating" a national grid that is "dispersed, interdependent and asymmetrical", the concept of local and regional expertise provides a much more effective means of triangulating and addressing risks.[138] These eight entities monitor NERC compliance through a number of discovery



[134] The Eastern Interconnection encompasses the area east of the Rocky Mountains and a portion of northern Texas and consists of 36 balancing authorities: 31 in the United States and 5 in Canada. The Western Interconnection encompasses the area from the Rockies west to the Pacific Ocean and consists of 37 balancing authorities: 34 in the United States, 2 in Canada, and 1 in Mexico. The Electric Reliability Council of Texas (ERCOT) covers most, but not all, of Texas and consists of a single balancing authority.

[135] There are also two "minor" interconnections: Quebec and Alaska. Texas is sometimes called a "minor interconnection" as compared to the Western and Eastern interconnections. Texas built its own power grid and is not connected to the rest of the country in order to avoid federal regulation of its electricity system.

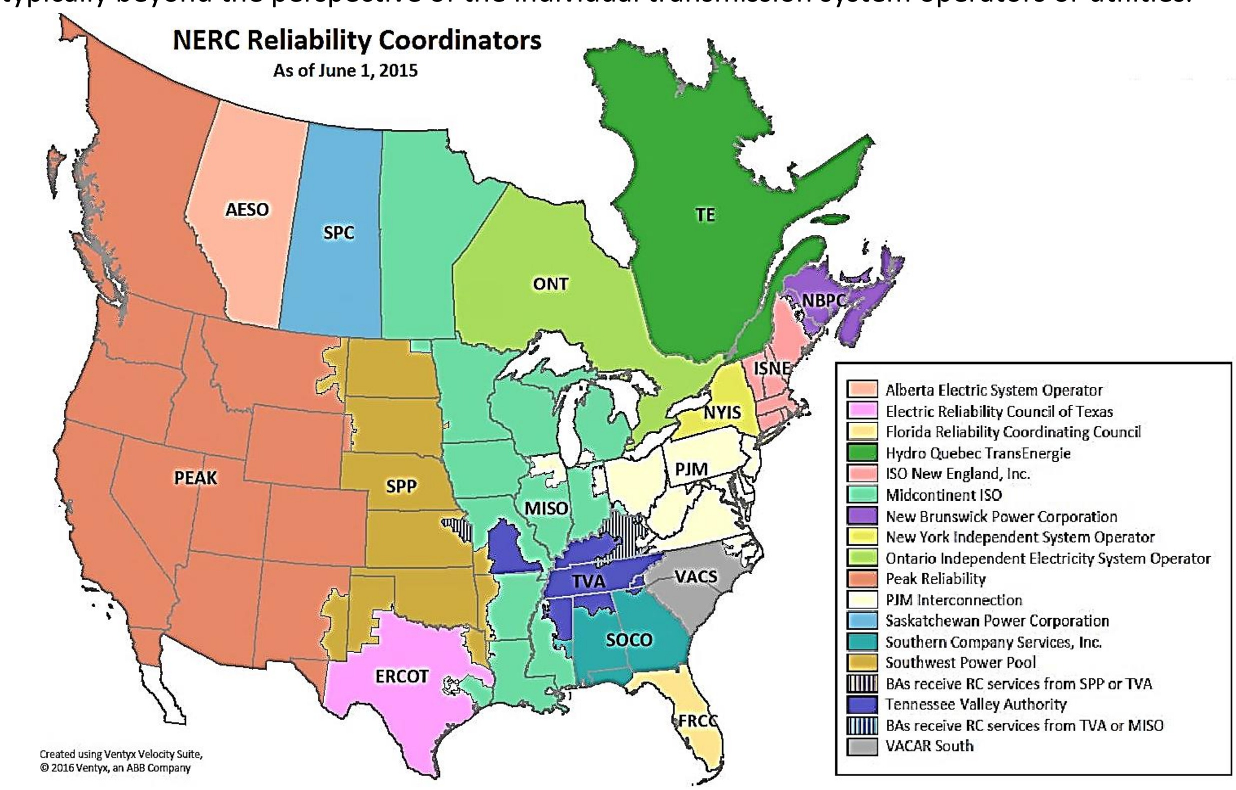
[136] A variable frequency transformer is a highly specialized piece of equipment that allows transmission of electricity between two "incompatible" domains; it operates like a continuously adjusting phase-shifting transformer.

[137] There are currently six DC ties between the Eastern and Western Interconnections and one in Canada. Note that these entities are isolated from each other, in part, to protect the integrity of the United States so that, in essence, a cascading outage cannot impact the entire country.

[138] "Improving Coordinated Operations Across The Electric Reliability Organization (ERO) Enterprise," February 2014, http://www.nerc.com/AboutNERC/keyplayers/Documents/ERO_Enterprise_Operating_Model_Feb2014.pdf

methods, including regularly scheduled compliance audits, random spot checks, compliance investigations, and a complaint process.[139] When a reliability standard requirement has not been met and violations are identified, financial penalties and other sanctions may be levied. The appropriate level of the penalties is based on guidance from FERC and NERC. These penalties can be up to $1 million per day per violation.[140] When a violation is identified, the parties use a NERC collaborative review process to identify what happened with the goal of learning from it and improving operations going forward to help insure that it doesn't happen again.

The eight Regional Operating Entities are further segmented into 18 **Reliability Coordinators,** who monitor their systems in real time, providing overall reliability evaluations to the Operating Entities (discussed below) within their regions. Reliability Coordinators are the highest level of operational authority for their part of the grid, ultimately responsible for the reliable operation of the Bulk Electric System within their footprint. They utilize operating tools, processes, procedures and authority to prevent or mitigate emergency situations in both next-day and real-time operations.[141] Their wide-area view allows them to calculate the Interconnection Reliability Limits for their entire section, which is typically beyond the perspective of the individual transmission system operators or utilities.

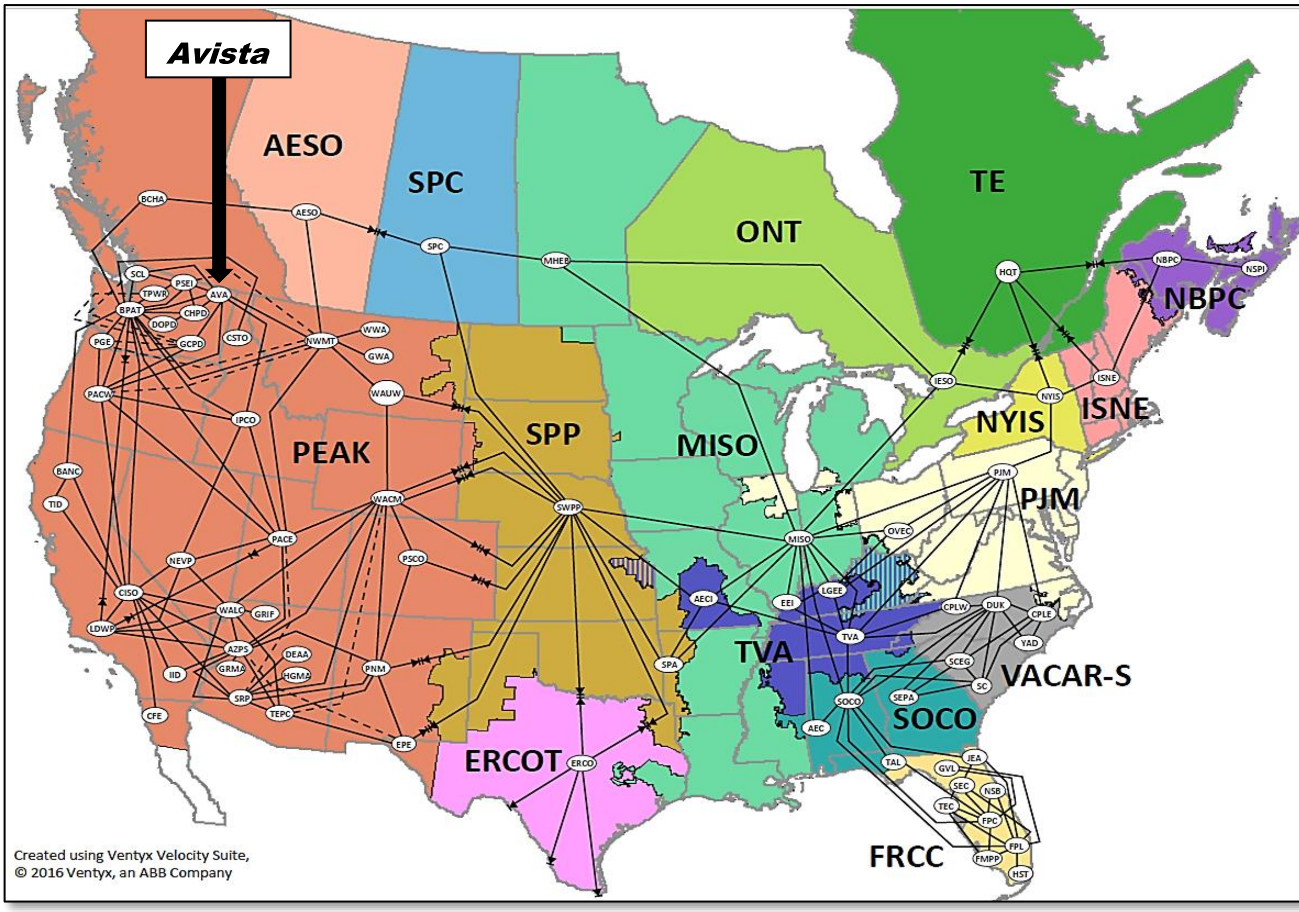


139 Any person or company may submit a complaint to report the possible violation of a Reliability Standard to NERC or WECC. "NERC-WECC Compliance Monitoring and Enforcement Program," January 1, 2011, http://www.nerc.com/pa/comp/Implementation%20Plans%20DL/2011%20WECC%20CMEP%20Implementation%20Plan.pdf, page 21, and https://www.wecc.biz/Pages/Compliance-UnitedStates.aspx, "Compliance Hotline – Complaints."

140 United States of America before the Federal Energy Regulatory Commission, Docket #PL10-4-000, http://www.nerc.com/files/FinalFiled_Comments_on_PenaltyGuidelines%20(2).pdf. Note that the penalties can be very large. In 2008 Florida Power & Light was hit with a $25 million penalty, primarily based on business silos existing in the organization. http://provencompliance.com/web/blog/152-highest-penalty-ever-unrelated-to-an-event

141 For more details about the levels of entities set out by NERC and the responsibilities of each, please see: "Reliability Functional Model," http://www.nerc.com/files/functional_model_v5_final_2009dec1.pdf

These 18 areas are further broken into **Balancing Authorities** and **Transmission Operators**. NERC defines a Balancing Authority as "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time." A Balancing Authority is the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority, and they are



NERC Balancing Authorities

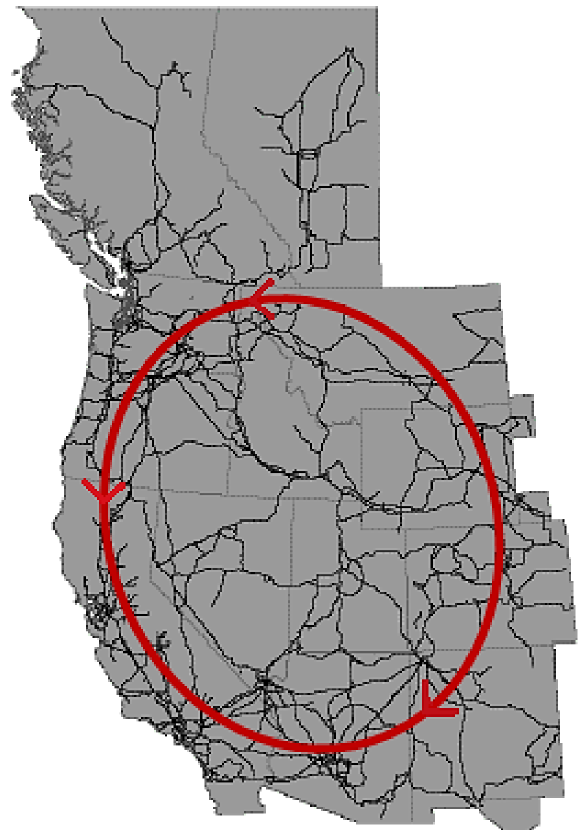
responsible for maintaining the load-resource balance within this area. Balancing Authorities manage load, generation, and interchange schedules, regulation, frequency response, contingency reserves, and area control error. They also manage reliability related services. A Balancing Authority does not operate transmission facilities; that function is performed by a Transmission Operator.

A Transmission Operator is defined as "the entity responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission Facilities."[142] The Transmission Operator is responsible for operational control and real-time reliability of the Bulk Electric System assets within its own area of the system. Avista is both a Balancing Authority and a Transmission Operator.

[142] NERC TOP-001-1 at http://www.nerc.com/files/TOP-001-1.pdf and NERC "Reliability Responsibilities and Authorities," http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TOP-001-1a&title=Reliability%20Responsibilities%20and%20Authorities&jurisdiction=United%20States

Western Electricity Coordinating Council (WECC)

Major Transmission Lines of the Western Interconnection



Western Electricity Coordinating Council Transmission System Typical Power Flow

Avista is a member of the Western Electricity Coordinating Council (WECC), one of NERC's eight Regional Operating Entities. The WECC is the largest and most diverse of all the Entities, extending over 1.8 million square miles and serving over 80 million customers from Canada to Mexico and the 14 Western states in between. The Western Interconnection is made up of approximately 121,200 circuit-miles of transmission in 66 primary paths and nearly 160,000 megawatts of resources.[143]

NERC designated WECC as an "informed regulator"[144] for the Western United States, expecting this organization to have a deep understanding of the Western interconnection and the risks and challenges this specific area faces, and to develop the appropriate risk-mitigating measures and activities.[145]

The WECC facilitates its member's cooperation in establishing operating processes related to physical security, training, reporting, maintenance, required equipment, apparatus settings, performance expectations, vegetation management practices, etc. It is also an enforcement entity. Typically, when a reliability standard has not been met, the entity will self-report the issue to WECC with a mitigation plan. Additionally, WECC audits entities on a three year cycle to ensure each entity is complying with the reliability standards.

NERC has also developed the Event Analysis Process[146] which is a voluntary process the industry uses to analyze Bulk Electric System events for root cause and to identify trends or emerging reliability issues. The Regional Entities, WECC in this case, work with the reporting entity to ensure that the Event Analysis reports are detailed as to what occurred, why it occurred, and how it can be prevented. These events are tracked and trended to identify emerging system reliability issues and to improve overall reliability by sharing the lessons learned from these events. The Event Analysis Process was put in place by NERC in October, 2010.

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143 Craig L. Williams, "Overview of WECC System Operations," WECC, May 4, 2015, https://www.wecc.biz/mwg-internal/de5fs23hu73ds/progress?id=ath6s2OHznCltlhNXnLRsB9VyRJmkJo1wxONpU1a8Eg,

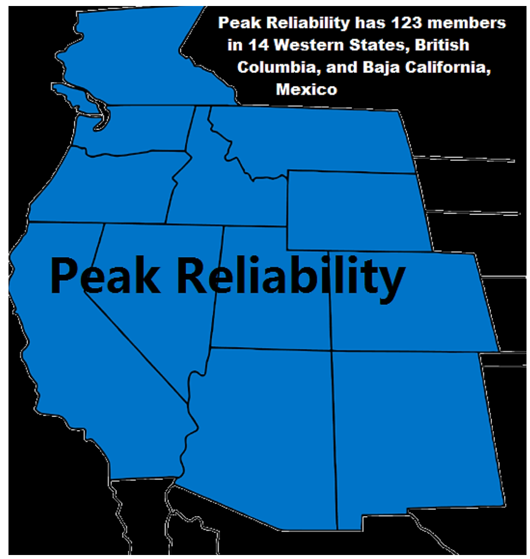
144 "Regulatory Philosophy: Western Electricity Coordinating Council", September 21, 2016, https://www.wecc.biz/Reliability/WECC-Regulatory-Philosophy-Final.pdf.

145 For a complete list of WECC Standards, please see https://www.wecc.biz/Standards/Pages/Default.aspx

146 For more information, please see: http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

As a regional entity, WECC was initially responsible for developing, monitoring, and enforcing standards for the reliability of the Bulk Electric System in the Western Interconnection. However, FERC raised concerns over the level of independence between WECC as a Reliability Coordinator **and** as a Regional Operating Entity, charged with reliability compliance and enforcement functions. As a result, in 2013 FERC granted WECC the authority to establish a separate, independent company to serve as the Reliability Coordinator within the Western Interconnection.[147] This newly created entity is Peak Reliability, a completely independent entity from the WECC. WECC continues to work with its members to ensure the general reliability of the Western Grid, helps members develop forecasts, coordinate operations, and perform planning functions. Peak is now the Reliability Coordinator for the Western Interconnection.

Peak Reliability



Peak Reliability (Peak), as a Reliability Coordinator, has the highest level of operational authority in its footprint, monitoring and ensuring the reliable operation of the bulk electric system within the Western Interconnection. Peak monitors system frequency and identifies sources of Area Control Error (ACE),[148] system operating limit exceedances, and inadvertent interchange.[149] Peak works with Balancing Authorities, Generator Operators, and Transmission Operators to ensure an uninterrupted flow of electricity to consumers. They have clear decision-making authority to act and direct actions to be taken to preserve the reliability and integrity of the Interconnection. Among the many tools Peak uses to do this are a system-wide model, which provides them with a view of the entire Western Grid in real-time. Peak ensures that the grid is operated within Operating Limits,[150] monitors Time Error Correction,[151] coordinates and directs restoration efforts if a blackout occurs, coordinates generation and transmission outages among entities, and monitors general operations related to the grid.[152]

It should be noted that neither WECC nor Peak have jurisdiction over construction of transmission facilities or any related siting, permitting, or cost allocation.

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[147] Troutman Sanders LLP, "FERC Grants WECC Permission to Divide into Two Entities," June 24, 2013, http://www.troutmansandersenergyreport.com/2013/06/ferc-grants-wecc-permission-to-divide-into-two-entities/

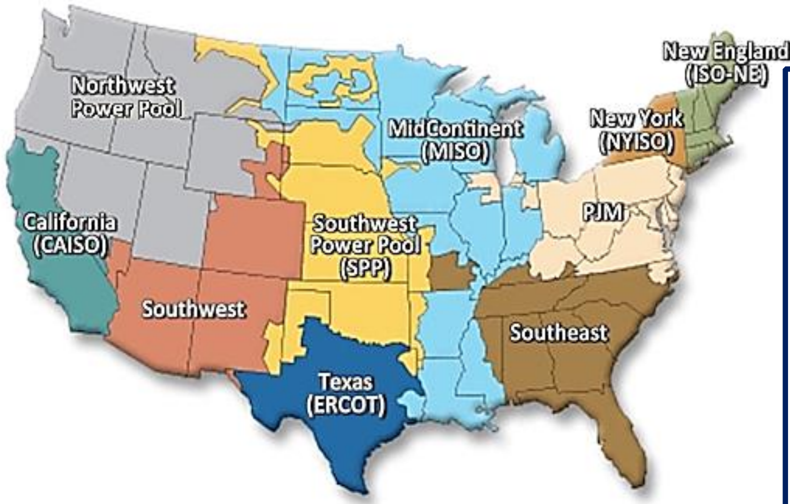
[148] Area Control Error (ACE) occurs when scheduled and actual generation within a control area don't match, which can place an undue burden on other utilities, cause unnecessary generator control movements, etc. For more information about this see: "Balancing and Frequency Control," http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

[149] Inadvertent interchange happens when more energy passes through a system than has been agreed upon, again impacting other utilities.

[150] Operating Limits are the values of MW, MVAR, frequency, etc. that satisfy the most limiting operating criteria for keeping the interconnections stable and reliable without violating NERC standards.

[151] Time Error occurs when the synchronous Interconnection operates at a frequency different than the Interconnection's scheduled frequency, resulting in an imbalance between generation and loads/losses and creating Inadvertent Interchange (when more energy passes through a system than has been agreed upon.) For some interesting information about Time Error and Time Correction, see Appendix H (page 92).

[152] Peak Reliability Coordinator Plan, http://www.nerc.com/comm/OC/ORS%20Reliability%20Plans%20DL/Peak_Reliability_RC_Plan_formatted.pdf



U.S. Power Markets

Northwest Power Pool

The Northwest Power Pool (of which Avista is a member) is not a regulating body. It is primarily a partnership among its 32 members[153] where public and private utilities, system operators, and government agencies coordinate operations and planning. This group developed a number of communally beneficial programs, such as a fully automated contingency reserve sharing program which allows members to immediately cover the loss of another member's generating unit. The NWPP also provided the means to successfully negotiate the Columbia River Treaty[154] between the U.S. and Canada. In order to be ratified by Canada's parliament, one unified stateside power entity was required so Canada would not have to deal with dozens of separate U.S. utilities. The NWPP provided this platform. The NWPP is not, unlike FERC, NERC, WECC and Peak, a regulating body, but it does have influence over Avista's practices and provides interconnection benefits.[155] Avista is a Balancing Authority within the NWPP.

Northwest Power Pool Members

- *Alberta Electric System Operator*
- *Avista Corporation*
- *Balancing Authority of Northern California*
- *B.C. Hydro*
- *Bonneville Power Administration*
- *Calpine Energy Solutions*
- *Chelan County PUD*
- *ColumbiaGrid*
- *Cowlitz County PUD*
- *Douglas County PUD*
- *Eugene Water and Electric Board*
- *FortisBC*
- *Grant County PUD*
- *Gridforce Energy Management*
- *Avangrid Networks*
- *Idaho Power*
- *NaturEner USA and Canada*
- *NorthWestern Energy*
- *NVEnergy (Nevada)*
- *PacifCorp*
- *Pend Oreille PUD*
- *Portland General Electric*
- *Powerex*
- *Puget Sound Energy*
- *Seattle City Light*
- *Snohomish County PUC*
- *Tacoma Power*
- *Turlock Irrigation District / TID Water and Power*
- *U.S. Army Corps of Engineers*
- *U.S. Dept. of Interior*
- *Western Area Power Administration*
- *Energy Keepers Inc.*

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[153] In 2016 the membership of the Northwest Power Pool included: Alberta Electric System Operator, Avista Corporation, Balancing Authority of Northern California, Bonneville Power Administration, British Columbia Hydro & Power Authority, Calpine Energy Services LP, Chelan County PUD No. 1, ColumbiaGrid, Cowlitz County PUD No. 1, Douglas County PUD No. 1, Eugene Water & Electric Board, FortisBC, Grant County PUD No. 2, GridForce, Iberdrola Renewable, Idaho Power Company, NaturEner, NorthWestern Energy, NV Energy, PacifiCorp, Pend Oreille County PUD No. 1, Powerex, Portland General Electric, Puget Sound Energy, Seattle City Light, Snohomish County PUD No. 1, Tacoma Power, Turlock Irrigation District, U.S. Bureau of Reclamation, Western Area Power Administration-Upper Great Plains, and Energy Keepers, Inc. The U.S. Army Corps of Engineers was also involved in the Northwest Power Pool as a signatory to the Pacific Northwest Coordination Agreement, but was not a signatory to the Power Pool Membership Agreement. The Northwest Power Pool covers an area encompassing eight states and two provinces.

[154] Jim Kirshner, "Pacific Northwest Coordination Agreement to Manage Power and Water on Columbia River System is Signed on September 15, 1964," http://www.historylink.org/File/11207 and "Columbia River Treaty," https://www.bpa.gov/projects/initiatives/pages/columbia-river-treaty.aspx For information on the Columbia River Treaty, please see: https://www.crt2014-2024review.gov/

[155] For more information about the NWPP, see: http://www.historylink.org/File/11199

ColumbiaGrid

In late 1999, FERC Order 2000 was issued. This Order encouraged a system of Regional Transmission Organizations (RTO) and Independent System Operators (ISO).[156] It was believed that this system would further separate the control of transmission from power marketers, as these organizations have no financial interests and are not controllable by marketers; they are completely neutral. FERC subsequently issued Order 890, which required every FERC-jurisdictional transmission provider to participate in a coordinated regional transmission planning process. Following an extended series of public processes, two primary regional transmission planning organizations were developed in the Pacific Northwest: ColumbiaGrid and the Northern Tier Transmission Group. Avista complies with FERC's transmission planning requirements through its membership in ColumbiaGrid,[157] a Washington-based non-profit. Due to the large presence of non-FERC jurisdictional entities in the Northwest, ColumbiaGrid's processes were carefully constructed to enable participation by these entities. In the independent spirit of the Northwest, ColumbiaGrid only performs those transmission-related functions that its members request.

North American ISOs:

- California ISO
- New York Independent System Operator
- Electric Reliability Council of Texas
- Midcontinent ISO
- ISO New England
- Alberta Electric System Operator

North American RTOs:

- New Brunswick Power System Operator
- Ontario ISO
- PJM Interconnection
- Southwest Power Pool

Non-RTOs: Western Regional Planning Organizations:

- Columbia Grid
- Northern Tier Transmission Group
- WestConnect
- Colorado Coordinated Planning Group

Key Areas of Regulatory Focus

Since June of 2007, NERC has implemented mandatory Reliability Standards related to the Bulk Electric System. Reliability Standards addressing system models, system planning methodologies, operating requirements, facility rating methodologies, personnel training, and other issues generally covering all aspects of grid

[156] The differences are very subtle. Both operate a regional, multi-utility grid, coordinating, controlling, and monitoring multi-state utilities, though an RTO typically covers a larger geographic area. RTO's have a closer tie to FERC regulation and have some added responsibilities, playing a more "hands-on" role in operating the system.

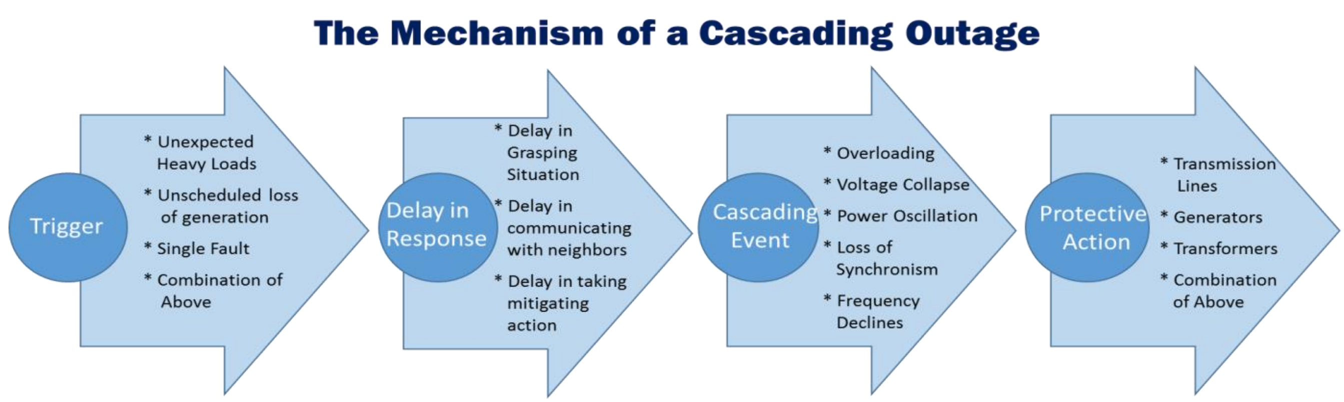
[157] ColumbiaGrid members: Avista, Bonneville Power Administration, Tacoma Power, Chelan County PUD, Grant County PUD, Puget Sound Energy, Seattle City Light, and Snohomish County PUD. The other transmission planning group in the northwest is the Northern Tier Transmission Group, which includes Idaho Power, Deseret G&T, NorthWestern Energy, PacifiCorp, and Portland General Electric. For more information about ColumbiaGrid, please see: https://www.columbiagrid.org/

operation and performance have been established. The intent of the Standards is to prevent a cascading and widespread blackout due to any credible contingency. There are currently approximately 100 NERC standards applicable to Avista. This number varies over time as new standards are developed and others are retired. Each Standard also has multiple Requirements which vary by Standard.

NERC Reliability Standards are designed to facilitate the engineering and construction of a power system that can be operated safely and reliably under all expected operating conditions. These expected operating conditions include the loss of generation resources or the credible outage of a transmission facility. The loss of a single system element is commonly called an N-1 operating condition or criterion. The normal system, with N elements, must be safe and reliable under the worst expected single contingency (N-1). In real-time operations, the system must always be in a configuration where the system is safe and secure for the next contingency. This second sequential contingency is often called the N-1-1 situation. Maintaining a safe and secure system for the next contingency requires:

1. A System Planning methodology that considers outages of key facilities due to planned or unplanned outages;
2. Operation of the system such that the system is always prepared to suffer the next contingency without creating cascading outages (a secure system);
3. Adequate generation resources to serve load;
4. Adequate generation reserve to replace generation lost due to a contingency.

The NERC Reliability Standards essentially codify the four previous points. It is important to note that in real-time operations, there are nearly always one or more facilities out of service due to maintenance or a forced outage. Operating to maintain system reliability under the next contingency in real-time can be very challenging, and requires careful planning and coordination of scheduled outages both internal to Avista and with external entities. It is essential that the planning and construction of the system be done to facilitate real-time operation of the system as it is actually operated.



NERC clearly recognizes that failures will occur:

> *"The brutal facts, as they say, are that utilities cannot afford to build or operate the interconnection to avoid all risks. The generation and transmission systems are finite and limited and always will be. At some point, the failure of a significant number of transmission lines will cause part of the Interconnection to become unstable and lose its integrity, regardless of automatic or system operator actions. And hurricanes and ice*

storms will take their toll. All the world's money cannot construct an electric system robust enough to remain unscathed from extremely unlikely and extremely severe events. While the consequences may be vast, some risks are simply unavoidable. Saying these consequences are also unacceptable is moot. Saying we don't want the events to happen is obvious. The important point is that we plan and operate the Interconnection so that credible contingencies result in acceptable performance. And after these contingences happen, the system operator is able to adjust the system to be able to handle the next credible contingency."[158]

That being said, the goal remains to keep the interconnection strong and stable through routine and expected events such as loss of a generator, a transformer or a line. FERC and NERC strongly believe that, though it is impossible to eliminate risk, proper planning and operations will reduce such risk, and that proper planning will ensure that after contingences happen, the system operator will be able to adjust the system to handle the next credible contingency and restore the system to full performance as quickly as possible.

As mentioned earlier, mandating the manner in which utilities plan their transmission systems is one piece of the FERC/NERC requirements puzzle. Operating the system is another. Several NERC Standards are related to transmission operations. System Planners perform long-range (greater than one year into the future) planning studies to design the system so it can operate within specific parameters of safety and reliability, and to be able to withstand events that may cause failure or outages. Operations Engineers study and plan for reliable system operations in the next day to next year timeframe. System Operators are responsible for ensuring that these well planned systems operate as intended and within very specific parameters in real time.

To NERC, interconnection integrity and equipment protection are a priority, as it believes that customer service depends upon maintaining the integrity of the interconnection and protecting generation and transmission equipment from catastrophic damage. Its goal is that the system is planned and operated in a way that if "credible contingencies"[159] occur, the system can isolate these events, preventing them from causing the interconnection to fail with a cascading outage.

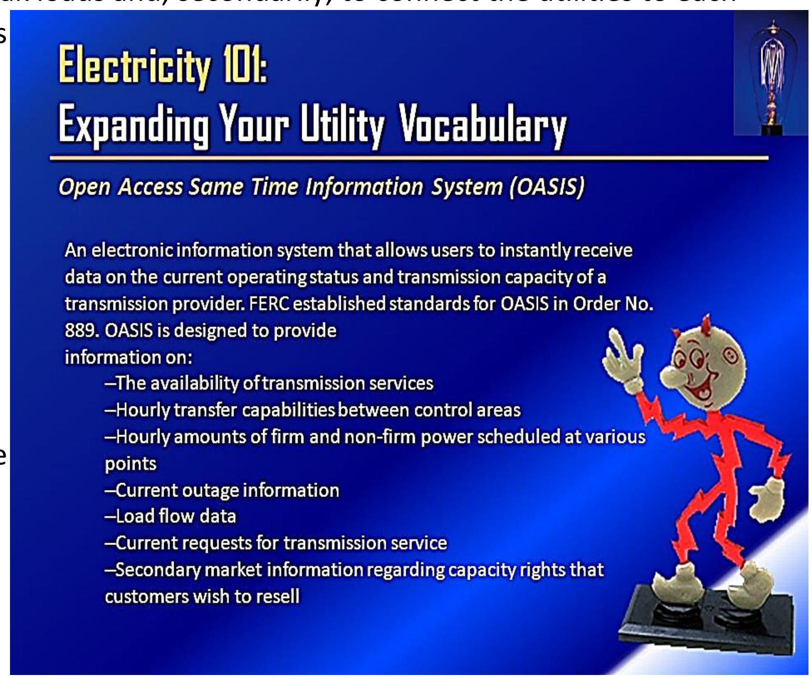
It is expected that this methodology will prevent customers from losing service, as the grid (and its operators) will respond in a way that maintains reliability to meet the sudden need for increased generation or to re-route around a failed facility. NERC's goal is always to maintain customer service, but not at any cost – it states clearly that a short term customer outage is preferable to loss of interconnection integrity or damage to equipment (which would ultimately result in longer term customer outages). Thus, System Operators manage risk in real time by monitoring and controlling

[158] NERC Reliability Concepts, Version 1.0.2, http://www.nerc.com/files/concepts_v1.0.2.pdf
[159] A "credible contingency" has two attributes: 1) plausibility / believability and 2) likelihood / probability.

generating dispatch and reserves, line flows, voltage profiles, load-generation balance, etc. This is done for two primary reasons: 1) to maintain interconnection integrity, and 2) to protect generation and transmission equipment from catastrophic failures and/or damage. The operator's success in achieving these expectations during normal operating conditions, emergencies, and system restoration activities directly impacts customer service in the short and long term.

Open Access to Transmission Markets

The North American electric system was originally designed to meet each utility's own native load customer needs for both average and peak loads and, secondarily, to connect the utilities to each other to support inter-utility transactions and provide greater reliability for the entire system. This system is, as we have noted, highly regulated by FERC and overseen by NERC and its eight Regional Operating Entities. However, increasing pressure to make the electric market more competitive and to allow non-traditional parties to participate in buying and selling energy pushed FERC into considering options to address these concerns.[160]



In 1996 FERC issued Orders 888 and 889,[161] which forever changed the manner in which electricity market participants gain access to transmission systems. Order 888 required public utilities to provide "non-discriminatory" open access to their transmission systems, and to provide transmission service to others under the same rates, terms, conditions and service priority that they provide for themselves and for their native load retail customers. Intending to facilitate a competitive wholesale market for energy, Order 888 opened the national transmission system to electric market competitors, created functional separation between transmission and marketing functions, required a standard form of open access transmission tariff, and gave utilities with large stranded investments (if they went through restructuring) the ability to recover those costs

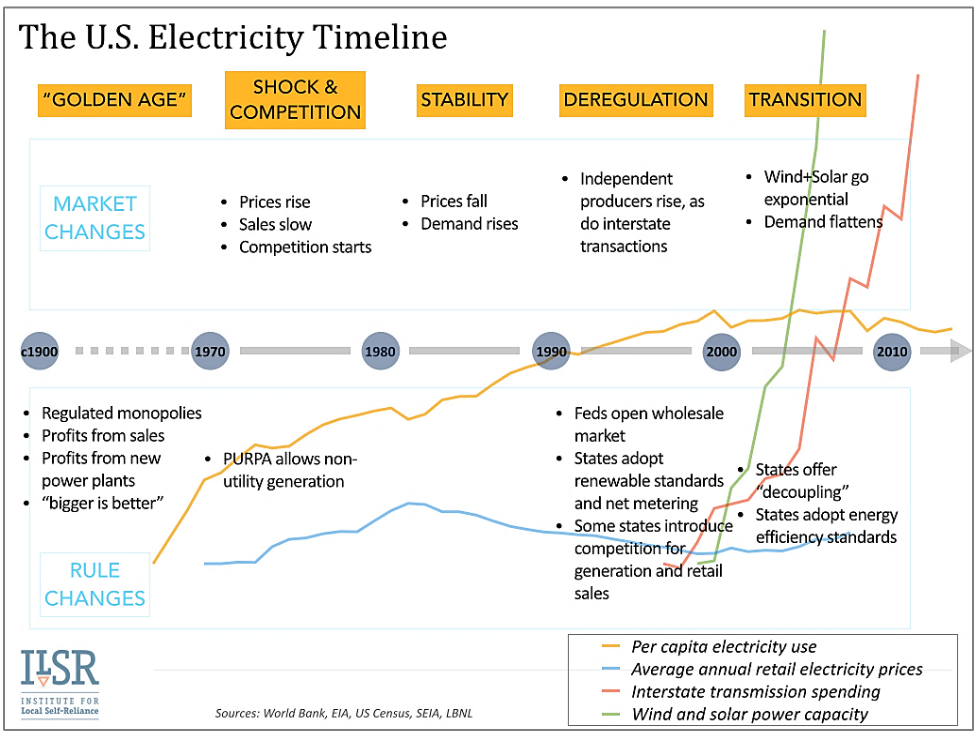
Ancillary Services for OASIS:

- Scheduling, System Control, Dispatch
- Reactive Power / Voltage Control From Generating Sources
- Generator Regulation and Frequency Response
- Energy Imbalance
- Generator Imbalance
- Spinning Reserve
- Supplemental Reserve
- Real Power Transmission Losses

[160] Electricity 101 graphic courtesy of http://slideplayer.com/slide/10915029/ Slide 7.
[161] For more information about Order 888 and Order 889, please see: https://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp and https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-9-00k.txt

from customers. It also unbundled transmission related charges, specifying a set of ancillary services. Ancillary services are system support services required to reliably operate the transmission system and a control area (such as load regulation, operating reserves and voltage control) and must be offered by each transmission provider and purchased by each transmission customer. These ancillary services must be offered and purchased individually rather than being bundled together when transmission service is provided. In essence, this Order enabled open access to the entire transmission system with the goal of reducing customer costs, adding increased reliability, and facilitating a competitive market for wholesale electric services.

With its companion order, Order 889, FERC sought to insure that transmission owners cannot have an unfair advantage over other market participants by having priority access to transmission information. This Order outlined the transmission capacity information that must be publicly available, and required each transmission provider to create a bulletin board to use in posting its information, called OASIS (Open Access Same-Time Information System). An OASIS is used to offer and reserve transmission capacity on each public utility transmission system. These bulletin boards are entirely internet based, and public access is limited to eligible parties: electric utilities (investor-owned, public power, co-ops), federal power agencies, Canadian and Mexican utilities that participate in the grid, or individuals generating electric energy for sale at wholesale rates.[162]



Gradually the transmission business has become a confusing mixture of regulated and unregulated services, with various companies controlling fragmented pieces. However, Avista has migrated successfully in accepting and adapting to these Orders, though implementation has added significant costs and operational issues and constraints.[163]

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[162] Note that retail customers can only obtain unbundled transmission service pursuant to state requirements or a voluntary offer of such service by a transmission provider. Entities that engage solely in brokering energy are also not eligible, as they do not take title to electricity and therefore do not engage in the purchase or sale of electric energy, nor do they generate energy. Findlaw "FERC Reaffirms and Clarifies Groundbreaking Rules on Open Access Transmission, Recovery of Stranded Investment and Operation of Open Access Same Time Information Systems," http://corporate.findlaw.com/litigation-disputes/ferc-reaffirms-and-clarifies-groundbreaking-rules-on-open-access.html and see Marcel Lamoureux, "FERC's Impact on Electric Utilities," http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=948252

[163] The "U.S. Electricity Timeline" chart source: "A $48 Billion Opportunity for U.S. Electric Customers," John Farrell, December 15, 2014, Institute for Local Self-Reliance, https://ilsr.org/u-s-utility-customers-save-48-billion-solar-efficiency/

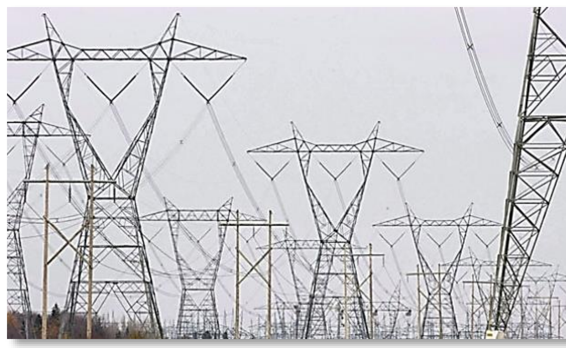
Appendix C: The National Transmission Grid

The national transmission grid, of which Avista is a part, connects utilities in North America to each other. This interconnectedness has several key advantages:

1) Provides ***enhanced reliability*** by diversifying both intermittent generation sources (such as wind or solar) and base load resources (such as hydro or coal), managing variances in generation and load across regions rather than just locally.

2) Enables ***remote generation*** resources – plants can be built in lower cost locations. Remotely sited resources (including renewables) can be integrated onto the grid and their energy sent to where demand exists, regardless of the plant's physical location.

3) Allows access to ***multiple generation resources*** even those outside a utility's own system. If one unit fails, the others on the system automatically increase to compensate. Mitigates interregional swings in load patterns; resources across a wide region can react and compensate. With interconnection, more resources are made available to make up for the variability, and utilities are able to aid each other upon loss of resources or equipment. Customers are less likely to suffer an outage.



4) Affords ***more paths*** over which bulk electricity can flow, so if one path is lost, there are other options to keep the power flowing.

5) ***Reduces the need to invest*** in transmission infrastructure, as a utility may not need to build a peaking facility if they can contract for that energy with another utility. Creates synergies between various transmission systems and utilities.

6) Multiple generators, owners, and costs provide ***economic competition***, helping keep electric rates lower and providing opportunities for utilities to sell excess energy to others or shop for energy needed to meet their own loads with price competition, ultimately reducing the costs to their own customers. Creates valuable trading opportunities across regions, and a competitive market for energy.

7) ***Reduces costs;*** allows lower cost resources to operate at optimum levels, as the output can be utilized across a wide area of load so these resources don't need to be backed down when regional load fluctuates. This is both cost effective and also easier on this equipment mechanically.

8) Provides additional levels of ***safety and fault tolerance margins***; more resources are available to meet reserve requirements system-wide.

9) ***Provides insurance***. Each utility is able to set aside less extra capacity in reserve in case of emergency; they know they can count on each other, so more of their generation can be used to provide service to customers rather than being held in reserve, reducing risk and cost. [164]

Bell-Westside 230 kV Line that Avista shares with BPA

However, there is one distinct disadvantage: the interconnections give system instability a wider channel over which to spread, and the sheer geographic size and diversity make it difficult to protect assets. Regardless, it is clear that a reliable and secure national grid and the interconnections it offers is in the best interests of customers across the nation.

As mentioned, the power grid is made up of many power generators, connected by transmission lines and substations. In order to work together, all of these generators must be synchronized, with equal line voltage, frequency, phase angle, phase sequence, and waveform. An AC generator cannot deliver power to the grid unless it is running at the very same frequency as the network. Connecting a synchronous generator to a large interconnected power system is a dynamic process, requiring a coordinated operation of many components and systems, with the goal of connecting a spinning generator to the system without causing any bumps, surges, or power swings. If a unit is brought online without being synchronized to the exact frequency of the operating grid, anything from a very loud bang to complete destruction of the unit is possible. Even rotating a little too fast or slow can cause a rapid acceleration or deceleration of the rotating parts and shear bolts or damage the shaft. In addition, as the external grid tries to "pull" the unit into line with the rest of the grid, transient power flows can be created, damaging equipment or creating oscillations that can cause cascading outages.[165]

Turbine failure in Australia when it went out of synchronization with the grid and its protection equipment failed

Normally a power grid is stable and does not oscillate on its own, but under certain conditions oscillation can happen if an attached generator becomes overloaded and lags behind, falling out of phase with the other generators, or if controls designed to keep the generator from lagging take too long to kick in. Special protective equipment is used to automatically synchronize generators to the grid at precisely the right frequency and to protect the integrity of the grid.

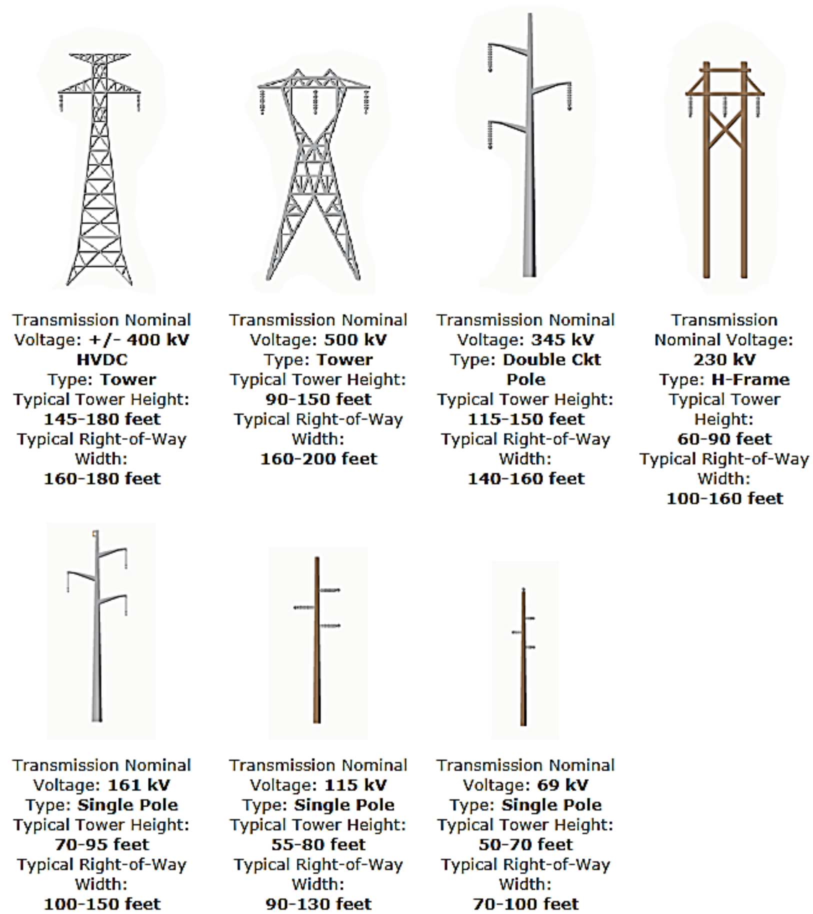
[164] United Nations Sustainable Development Knowledge Platform, "Economic and Financial Impacts of Grid Interconnection," http://www.un.org/esa/sustdev/publications/energy/chapter3.pdf

[165] For a great discussion on oscillation, please see: "An Overview of Power Grids," https://midimagic.sgc-hosting.com/powgrid.htm and https://www.linkedin.com/pulse/south-australia-powering-up-grid-takes-time-justin-wearne

Appendix D: AC Versus DC Lines

Most transmission lines are high voltage three-phase alternating current (AC), though high voltage direct current (DC) lines provide greater efficiency over very long distances with very little line losses. However, AC has a couple of distinct advantages: large electrical generators happen to generate AC naturally, so no conversion is required, and AC equipment is ultimately less expensive when it comes to repair, maintenance, and equipment costs. Expensive (and very large) converter stations are needed at each end of a DC line to convert its power to a usable level for customers. In addition, transformers don't work for DC power and the ability to change voltages is important, as different classes of loads (for example lighting versus motors) require different voltage levels.

The AC and DC options have been compared to a local versus an express train. Local trains (AC lines) allow people to get on and off at different stops with a great deal of flexibility, but are not efficient if the end of the line is your destination. Express trains (DC lines) can move a lot of people over a long distance extremely efficiently, but with limited flexibility. However, DC systems compliment AC systems nicely. In the United States, DC lines are used to connect to AC systems that are not synchronized, allowing the transfer of power from one AC grid to another (such as the Eastern and Western Interconnects, which are slightly out of phase.) It is also a very attractive option in connecting remote areas with complementary power needs, as with the Pacific Intertie, which runs from Oregon to Southern California. In the summer, the Pacific Northwest typically has a lot of hydropower available just when Los Angeles can use extra power to cover its big summer air-conditioning peak. Power generated from Northwest hydropower plants can hop on the DC Intertie and run directly to L.A. In the winter when the Northwest's reservoirs are largely depleted, Southern California can help with Northwest winter heating peaks by sending generation to the north. DC lines allow very large amounts of power to efficiently flow north or south depending on the different regions' peaking needs.



Appendix E: NERC Corrective Action Events

Table 1 – Steady State & Stability Performance Planning Events

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No [9]	No [12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No [9]	No [12]
		2. Bus Section Fault	SLG	EHV	No [9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No [9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes
P3 Multiple Contingency	Loss of generator unit followed by System adjustments [9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No [9]	No [12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker [10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No [9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker [10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay [13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No [9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments. [9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Appendix F: Siting Transmission Lines

It is important to note that transmission planning and construction is becoming increasingly complex. It used to be that utilities planned for reliability and facilities based on local load growth, generation and load interconnections. With FERC and NERC regulations in place, utilities must now plan for strictly regulated reliability requirements; they must develop system hardening and resiliency to minimize adverse events (primarily related to terrorism and vandalism), accommodate ever-changing public policy regulations and the associated uncertainty, enhance grid security, consider impacts on neighboring utilities and the interconnected system, and provide ever greater flexibility in operations. In addition, transmission is impacted by shifts in generation such as increasing numbers of renewable resources and reductions in traditional generation sources. All of these issues often require adding or enhancing transmission.

Building transmission lines presents a number of constructability issues, with three primary barriers: public opposition, environmental concerns, and regulatory complexity. Although FERC has jurisdiction over interstate transmission commerce and the federal government has authority over siting transmission lines on federal lands (which make up a significant percentage of land in many western states), states retain jurisdiction over actually permitting and siting transmission lines, even if they cross state lines. Generally, states define transmission lines as a public use, which allows the application of eminent domain upon payment of just compensation under the Fifth Amendment to the U.S. Constitution. In Washington[166] and Idaho[167], utilities can condemn properties to build transmission if it is determined to be for public use, with each state having a process that must be completed before this can occur. Washington gives counties broad eminent domain powers and declares that the exercise of these powers is a public use when "it is directly or indirectly, approximately or remotely for the general benefit or welfare of the county or of the inhabitants thereof" (Rev. Code of Wash. § 8.08.20).[168]

In Washington, the Washington Energy Facility Site Evaluation Council is responsible for siting transmission of 115 kV or greater in agreement with local jurisdictions. The process for obtaining site approval for electric transmission facilities in Washington comprises several steps, including undergoing a preliminary site study, completing a detailed application proposal, public hearings, a recommendation to the governor, and finally a Site Certification Agreement (SCA) executed by the Governor.[169] It typically involves a detailed Environmental Impact Statement as well as air, water, and hazardous waste permits. Interestingly, in Washington the applicant is not required to demonstrate the need for transmission, because the Washington State Legislature has already declared the "pressing need for increased energy facilities" in the state.[170] In addition, the Council is explicitly

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166 US Legal, "Washington Eminent Domain Laws," https://eminentdomain.uslegal.com/state-laws-on-eminent-domain/washington/
167 US Legal, "Idaho Eminent Domain Laws," https://eminentdomain.uslegal.com/state-laws-on-eminent-domain/idaho/
168 Kevin E. McCarthy, "'Public Use' and Eminent Domain," OLR Research, July 27, 2005, https://www.cga.ct.gov/2005/rpt/2005-R-0570.htm
169 James A. Holtkamp and Mark A. Davidson, "Transmission Siting in the Western United States," 2009, https://www.hollandhart.com/articles/transmission_siting_white_paper_final.pdf
170 Washington State Legislature WAC 463-60-021, http://apps.leg.wa.gov/wac/default.aspx?cite=463-60-021

prohibited from considering the fuel source of the electricity carried by the proposed transmission facilities.[171]

One of the problems with state authorization is that each state will naturally focus on the needs of its own citizens. However, interstate transmission lines provide regional or even national benefits that may overshadow any in-state benefits. This is particularly true for long distance transmission lines that bring renewable energy from remote locations to population centers that may be one or even several states away. While the state with the long distance transmission line crossing it may see minor benefits in increased grid reliability, that benefit may not be outweighed by physical impacts to property, viewscapes, natural resources, or the environment that the state must face.

Another issue creating significant time delays is allocating costs among the various entities that would benefit from the line and ensuring that the line meets the requirements and needs of all affected parties, as touched upon in the regulation section above. Obtaining funding is also an issue. In addition, costs for raw materials are increasing rapidly; the United States is competing in a global market for transformers and other components of the electrical system. The United States currently imports 85% of its large power transformers, competing directly with rapidly expanding electric systems in China, for example, for raw materials and limited production.

Siting transmission can also be a polarizing issue, sometimes requiring years to get through. Not only are utilities dealing with the familiar NIMBY principle (Not In My Back Yard), but they are now seeing more extreme positions (such as BANANA: Build Absolutely Nothing Anywhere Near Anything). Issues including public opposition, environmental and geographic constraints, interagency coordination problems, and local, state, and federal regulations all create huge barriers to permitting and construction. Given the scope of the constraints affecting new projects, siting transmission is a broad, complex problem for which solutions are not obvious or well understood. To make matters worse, transmission lines are particularly visible and impact multiple government agencies, all of which have their own agendas.

A siting study by Holland and Hart sited a “bewildering variety” of federal, regional, state and local requirements for siting, building, and operating a transmission line. Their study noted that not only do many people object to the aesthetic and other impacts of a major power line in their own communities, but there is a growing number of objections to power lines in remote areas due to environmental and recreational impacts.[172] One estimate is that actually getting a new transmission line built can take up to 10 years or longer.[173]

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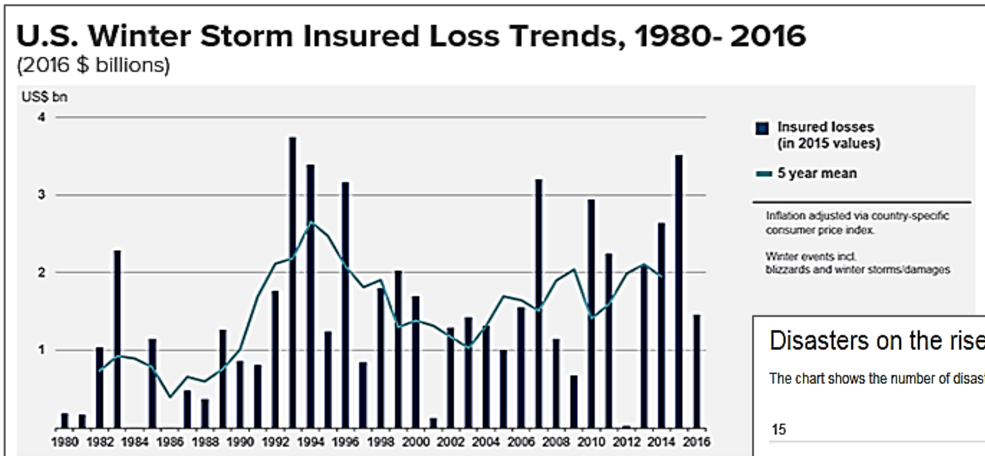
[171] In other words, no favoritism is allowed for renewable resources. Washington State Legislature Washington Revised Code Title 80. Public Utilities § 80.50.045, http://codes.findlaw.com/wa/title-80-public-utilities/wa-rev-code-80-50-045.html

[172] James A. Holtkamp and Mark A. Davidson, “Transmission Siting in the Western United States,” 2009, https://www.hollandhart.com/articles/transmission_siting_white_paper_final.pdf.

[173] Gail Tverberg, “The U.S. Electric Grid: Will It Be Our Undoing?” May 7, 2008, http://www.resilience.org/stories/2008-05-07/u-s-electric-grid-will-it-be-our-undoing/

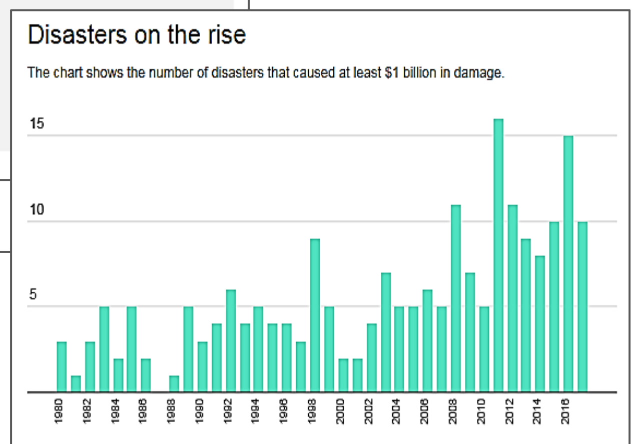
Appendix G: Changing Weather Patterns

Below are several charts showing data related to weather, most of which were put together by the National Oceanic and Atmospheric Administration or Munich Re, a widely respected worldwide insurance provider. These charts indicate the increasing number of large weather events that impact the grid:

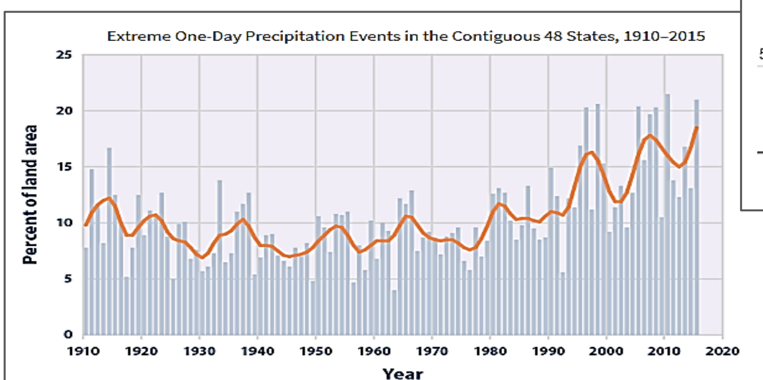


Source: © 2017 Munich Re, Geo Risks Research, NatCatSERVICE. As of February 2017.

Above Source: Munich Re

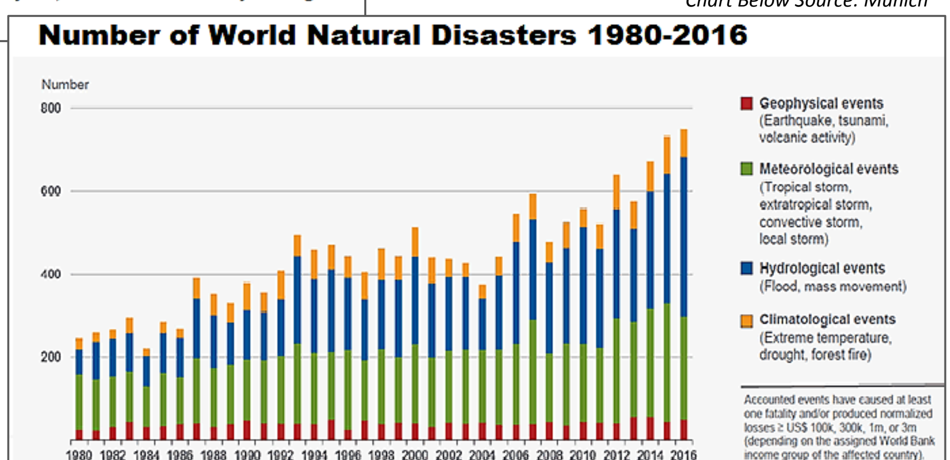


Above Source: NOAA



This figure shows the percentage of the land area of the contiguous 48 states where a much greater than normal portion of total annual precipitation has come from extreme single-day precipitation events. The bars represent individual years, while the line is a nine-year weighted average.

Chart Below Source: Munich

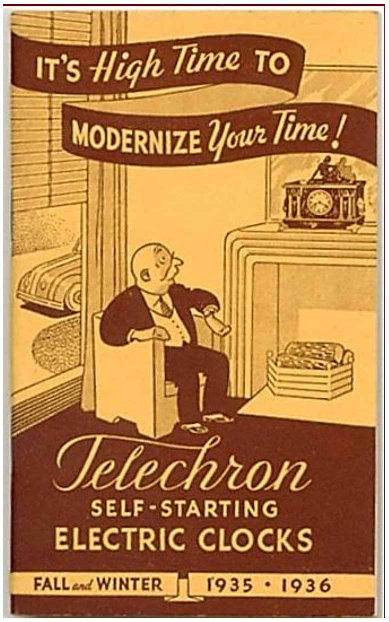


Source: Munich Re. Geo Risks Research. 2017

Note: Munich Re is an international insurance company widely recognized for their expertise on weather-related disasters.

Appendix H: How The Grid Controls Time

Since 1930 electric clocks have kept the time based on the rate of the electrical current that flows through them at 60 cycles per second (though it often varies between 59.98 and 60.02). If that current changes, clocks run a little faster or a little slower. Utilities take steps to keep the frequency of the current – and thus the time – as accurate and precise as possible.

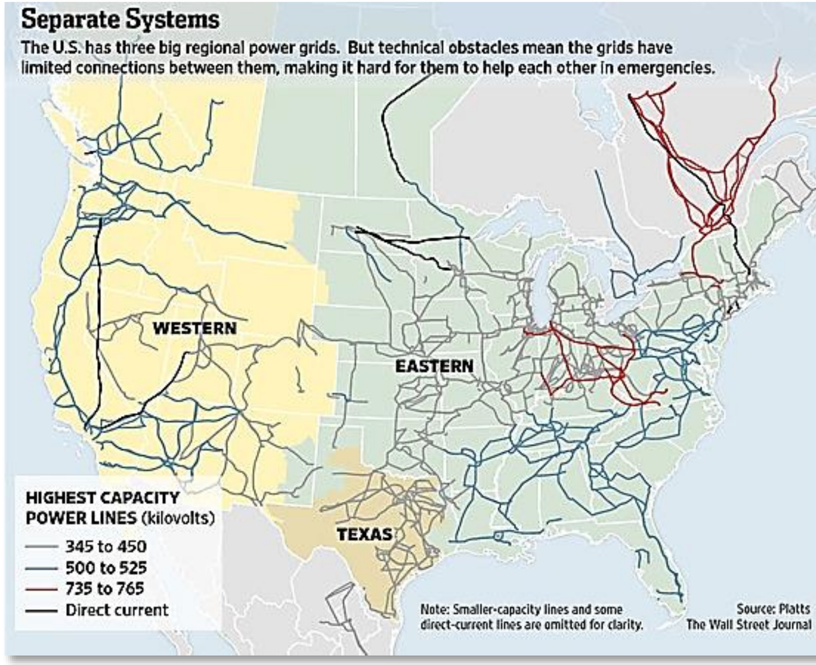


This all started in 1916, when Henry E. Warren invented the self-starting synchronous motor. Three years later the motor was used for the production of the Telechron Clock. The Telechron Clock was a synchronous electric clock which used alternating current (AC) electricity to measure time. Its accuracy depended on the frequency of the power grid. To incentivize electric system operators to regulate frequency in a way that kept the clocks running accurately, the Warren Clock Company, which was manufacturing the Telechron Clock at the time, gave free electric clocks to electric system operators. The idea worked! System operators began regulating the frequency as desired by the Warren Clock Company.

During the 1920s, other companies developed synchronous motor clocks and used the same marketing strategy, giving away electric clocks to system operators. In 1926 Lauren Hammond gave away hundreds of electric clocks with synchronous motors to power station owners, encouraging them to maintain a steady 60-cycle frequency. His inexpensive clocks became "uniquely practical" in homes and businesses as well. The message began to spread. As the penetration of the synchronous electric clock increased, the incremental electric revenue to utilities from the additional electric clock motors justified the relatively small cost to utilities to regulate system time by modifying system frequency. This additional revenue helped ensure that manual Time Error Correction (TEC) would be an ongoing service provided by the electric utility industry, and that remains the case today.

As the electric system became more interconnected, the service of providing manual TEC was incorporated into the industry's general operating practice. The current form of manual TEC is a legacy commercial practice that originated in the 1920s as a commercial service and was not related to the reliability of the electric grid. While documentation is available from as late as 1976 that synchronous electric clocks are still being used for important applications, by 1969, alternative methods of keeping accurate time penetrated the market and gradually displaced the electric clock. For example, the introduction of the first mass-produced quartz watch provided a more reliable and less expensive method to keep accurate time. Additionally, 15 years later, the United States made the Global Positioning System available for free, which is a space-based satellite navigation system that provides location and time information. However, today power network operators still regulate the daily average frequency so that electric clocks stay within a few seconds of the correct time.

Appendix I: Key Transmission Operations Positions



NERC Electrical System Interconnections[175]

Using near-term system models, Operations Engineers perform studies covering the next day to the next year by modeling loads, resources, transmission configuration, outages, reactive support, operating limits, and interchange schedules to insure that strategies are in place to manage their respective portions of the Interconnection and to be prepared for the next credible contingency (or worse). Operations Engineers and System Operators are responsible for keeping the system within its operating limits, mitigating unexpected events, and restoring the system if, heaven forbid, a blackout occurs.[174]

Avista's Operations Engineers develop System Operating Procedures (SOPs) that are reviewed and updated annually. These Procedures provide System Operators a plan or road map in addressing certain operating conditions or contingencies. Avista currently has 38 such SOPs.

System Operators go through extensive internal and external annual training and must be certified by NERC prior to working in one of the two real-time system operations positions. The first position is the Transmission Operator, who is responsible for all switching activity on the transmission system, including communications with crews who are working on the lines. The other key position is the Reliability Operator, who is responsible for monitoring the Company's generation resources, system load levels, and power schedules to, from, and across the transmission grid. Avista must also coordinate all of its planned outages of either generation or transmission facilities with all of its regional neighbors to insure that the broader regional transmission grid, under the purview of Peak Reliability, is able to be operated reliably and that the potential impact of Avista's scheduled outages is mitigated.

> **"You can't just look at your system. You've got to look at how your system affects your neighbors and vice versa."** *- Arshad Mansoor, vice president of power delivery and utilization with the Electric Power Research Institute (EPRI)*

The specialized positions related to operating Avista's system will be discussed in a bit more detail on the following pages.

[174] Note that a System Operator has NERC authorization to shed load if they see no other way to return the system to its acceptable operating limits within an acceptable time frame.

[175] Graphic courtesy of Rebecca Smith, "U.S. Risks National Blackout From Small-Scale Attack," The Wall Street Journal, March 12, 2014, https://www.wsj.com/articles/u-s-risks-national-blackout-from-small-scale-attack-1394664965

Outage Coordination

As mentioned, one of NERC's primary focus areas is grid reliability. As an interconnected system, each utility's operations have the potential to impact their neighbors or even the entire grid. The Outage Coordination Process is designed to provide a way to coordinate substation, transmission,

communication and generation outages in a way that ensures that the entire North American system is operated in a known and reliable state and that outage impacts are mitigated. NERC mandates the basic requirements for outage coordination in Standards IRO-017-1[176] and TOP-003-3[177] which require every Reliability Coordinator, Transmission Operator (TOP) and Balancing Authority (BA) to have a specific process in place for handling outages. Avista's Reliability Coordinator is Peak Reliability (for more information on Peak Reliability, see page 78).

Peak requires that outages be scheduled and submitted consistent with their Outage Coordination Process, which includes an online tool called the Coordinated Outage System. This tool allows Peak to collect and view all outages across the interconnection. Their operations engineers utilize a modeling program that simulates the system so they can study potential impacts on the grid. Peak reporting requirements apply to their associated Balancing Authorities, who are required to provide generation outage information. These reporting requirements also apply to Transmission Operators, who are required to provide transmission-related outage information. Avista is both a Balancing Authority and a Transmission Operator within the Peak jurisdiction, and has an Outage Coordinator who is responsible for managing both areas.

At Avista, the Outage Coordinator position is filled by either a senior system operator or an experienced electrical engineer. They are responsible for providing the necessary interface between System Operations, field personnel, neighboring utilities, internal departments, and construction

offices. This position ensures continuity, consistency and coordination of required work activities pertaining to outage coordination on the interconnected Bulk Electric System, including generation and substation outages. This position is tasked with the authority and responsibility to operate the Avista transmission system in such a manner as to comply with all appropriate NERC and Peak Reliability Standards. The Outage Coordinator creates accurate switching orders, resolves construction scheduling

[176] NERC Outage Coordination, IRO-017-1, http://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-017-1.pdf
[177] NERC Operational Reliability Data, TOP-003-3, http://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-003-3.pdf

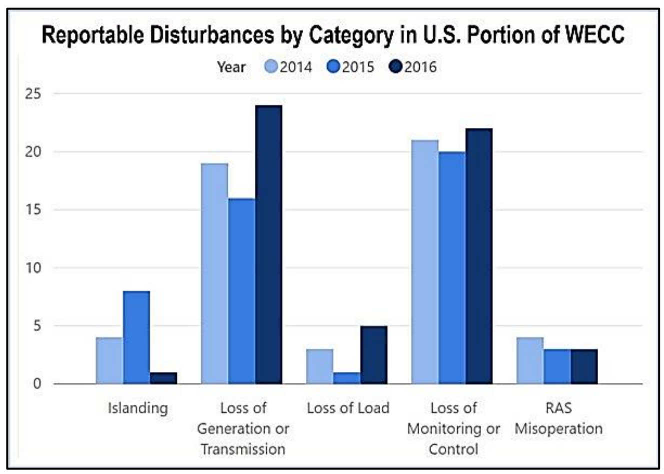
conflicts, organizes and leads outage coordination meetings, and develops and maintains switching standards for Avista System Operations.

Both transmission and generation outages have the potential to cause or contribute to regional operating area limits or to impact neighboring utilities. For prescheduled outages, the Outage Coordinator notifies anyone who might be affected to give them a heads-up and awareness of the event. If an outage happens in real-time, the System Operator makes these same notifications. The Outage Coordinator plans and coordinates outages with any other Balancing Authorities or Transmission Operators (neighbors) who may be affected, strategizing with them on what may be needed for system reliability and insuring communication is in place so they can coordinate closely during the outage.

The Outage Coordinator is also responsible for insuring that adequate studies and assessments have been done before an outage is approved to ensure that no reliability issues will be created. The Outage Coordinator is responsible for keeping all affected parties informed on the planning, status, and any updates related to planned or unplanned outages.

Note that Peak has the authority not only to study the potential impacts of a planned outage, but also to approve or deny it.

System Operator Training



System Operations controls the transmission and generation system in real time. They are mandated by NERC Standards requiring that utilities maintain frequency, voltage, interchange and system stability within acceptable ranges and respond to emergencies accurately and within a specified time frame. System Operators must respond to ever-changing conditions of normal operations and emergency conditions due to weather, equipment malfunctions, public accidents and even vandalism and sabotage.

This high level of responsibility requires experienced, highly capable and well trained employees that must pass a national certification test administered by NERC. System Operators at Avista are seasoned employees that normally come from the crafts, such as generator operators, electricians and linemen. They must be individuals who have excellent communication and critical decision making skills, as well as the ability to act thoughtfully and calmly under the extremely stressful and challenging conditions that can accompany an unexpected outage.[178]

[178] Reportable Disturbances graphic courtesy of Jason Fordney, "WECC Generation, Transmission Loss Events Spike," June 18, 2017, RTO Insider, https://www.rtoinsider.com/wecc-western-interconnection-44464/

Reliability Desk

Avista has a robust in-house System Operator training program that meets NERC requirements in PER-005-2.[179] This program follows a systematic approach to training as mandated by NERC. Each operator must go through a rigorous initial training program, and then pass the NERC certification test. Upon completion of their certification, Operators go through an "on the job" training program before they are able to cover a shift. During this on-the-job-training (OJT) they must be signed off as being competent in over 80 tasks.

Once these tasks are completed, the trainee is qualified to work on the reliability desk. This desk is responsible for generation and interchange monitoring as well as responding to emergency conditions related to load and generation. They must perform their tasks in accordance with all NERC standards. The reliability desk operators also assist the Transmission Reliability Operator and continue to receive training to be able to progress to the Transmission Operations Desk.

Typical Utility Dispatch Center

Transmission Operations Desk

The Transmission Reliability Operator must go through more OJT and be qualified in an additional 140 tasks (beyond those required for the Reliability Desk). These tasks include everything from monitoring the system, issuing clearances, to emergency operations and more. Once they have been signed off as being competent in these tasks, they are qualified to operate the Transmission Operations Desk, also referred to as the "senior desk."

NERC also requires continuing training to maintain NERC certification. All System Operators receive 200 hours of continuing training every three years. Avista has an in-house training program administered by the System Operator Training Coordinator, which includes training on all of the system operating procedures, NERC standards, and emergency operating procedures, including restoration following full blackout of the system. Much of the training includes use of a simulator. The training program is reviewed yearly by the Chief System Operator, the Training Coordinator, the Senior Operations Engineer and the System Operators. The effectiveness of the program is reviewed and checked for any errors or deficiencies. Individual development plans are prepared for each System Operator as well to ensure that all operators are receiving the required training.

Avista also participates in regional restoration training provided by the Regional Reliability Coordinator. This is a yearly event and includes all of the entities in the Northwestern United States. This training simulates a widespread blackout, with all of the entities working together to restore the electrical system. This exercise helps build cooperation, coordination, and camaraderie between utilities as well as enhancing expertise.

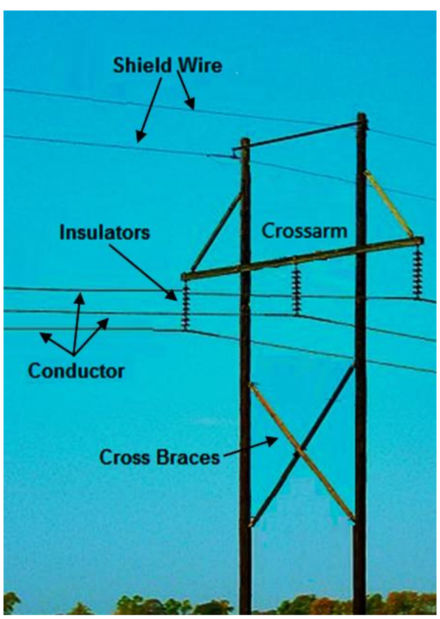
[179] NERC Operational Personnel Training, PER-005-2, http://www.nerc.com/pa/Stand/Reliability%20Standards/PER-005-2.pdf

Appendix J: Transmission System Equipment

Conductor: Conductor is large wire, usually 1-2 inches in diameter, made up of multiple aluminum strands surrounding a steel core that work together to carry electricity.[180] The conductor is strung between transmission structures. A "line" is typically comprised of a single conductor or multiple (up to four) conductors bundled together. All transmission lines generate a small amount electrical discharge, or corona, which causes the surrounding air molecules to ionize. At times you can hear this effect as a slight humming or crackling sound close to a line. Corona is accompanied by power loss and can even damage electrical components over time, as the gases released by it are corrosive. Higher voltage lines and larger diameter conductor reduce the corona effect and also create less resistance and resulting losses. To create larger lines and further reduce the corona effect, conductors are bundled together to increase the effective diameter of the conductor. Bundling also allows a line to carry more capacity. Conductor cannot be put under too much tension or it will fail. Therefore it is attached to structures in a way that creates a dip in the lines between structures. Determining the proper amount of sag is a complex calculation that takes into account clearance to ground and to other conductors on the same line, length of the span, tension and weight of the conductor, relative location of poles to each other (such as going up a hill), and external factors such as heat, loading, wind, ice weight, and ambient temperature.

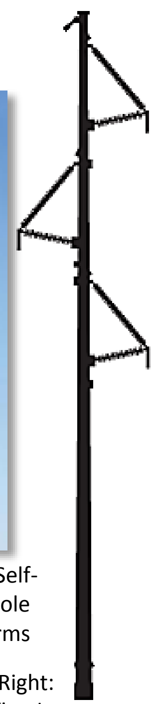

Transmission Conductor

Structure: Transmission poles are the most visible component of the electric transmission system. Their primary purpose is to keep the high-voltage conductors separated from their surroundings and from each other while providing the means for the conductor to travel from the generation source to the substation. These structures are typically between 60 and 140 feet tall. Structure designs vary by utility and depend in great part on load/capacity, weather, geographic settings/terrain, access/transportation, soil conditions, distance between structures, right-of-way widths, cost, and pole height

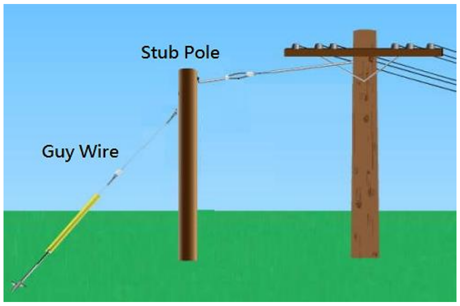


Above: Transmission H-Frame Structure


Above: Steel Self-Supporting Pole with Davit Arms

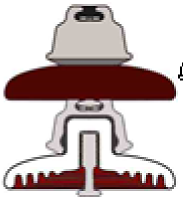

Right: Steel "Armless" Pole

[180] Aluminum is used because it is highly conductive and light weight. Aluminum is 61% conductive versus steel, which is 3-15% conductive. Source: "Which Metals Conduct Electricity?" https://www.metalsupermarkets.com/which-metals-conduct-electricity/

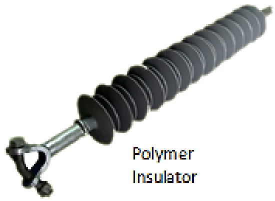


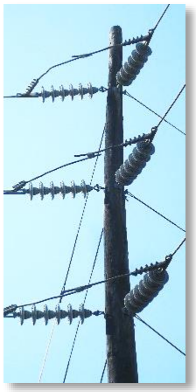
required to meet clearance requirements. In addition, different types of poles may be needed at the point where a line changes direction. This adds additional stress to a structure, and often requires guy lines, stub poles, or self-sustaining structures for additional strength. Structures can include a single steel or wood pole with a cross-arm, or have "armless" construction, in which insulators are attached directly to the side of a pole. Other types of structures include the "H Frame" or a lattice tower. Structures must be designed to carry the loads imposed on them by the weight of the conductor plus wind, ice accumulation, heat, and vibration. They must be also be tall enough to keep the conductor above the ground at a level that meets safety requirements established by the National Electric Safety Code.

Insulator: An insulator is usually made of glass, porcelain, or a composite polymer. They are used to attach the conductor to a transmission structure/pole in order to prevent short-circuiting. Insulators are frequently shaped like umbrellas with what are sometimes called "petticoats" to allow rain to drip away from the bottom of the insulator to help prevent flash-over. Depending on voltage level, insulator strings are mounted on a crossarm or tower as shown in the photograph on the right. Another common type of insulator is a strain insulator that is used when there is a lot of tension on the line, such as at a sharp corner.



One Piece Insulator

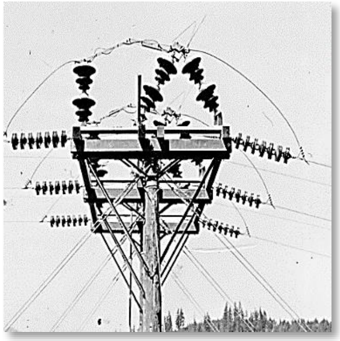




Above: String of Glass Insulators
Left: Strain Insulators on a corner pole

Jumper: At times insulator strings are mounted on each side of a pole and are electrically connected by a jumper conductor to make the connection complete and ensure continuity of the line. Transmission lines typically have jumpers when the line has been dead-ended on a pole due to the line ending or making an angle. The jumper allows the line to get to the dead-end on the other side of the pole so it can continue on, keeping the connection intact.

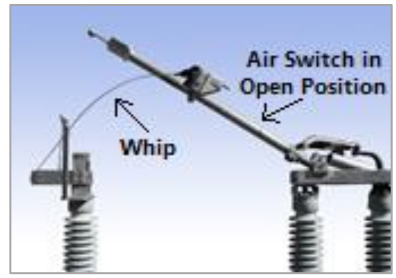
Jumpers on Avista lines today



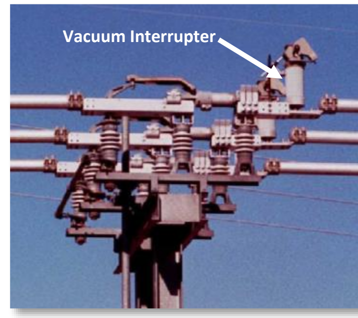
Jumpers on an Avista line in 1926

Air Switch: High-voltage air switches are installed in electrical transmission networks to de-energize line sections between substations. This allows construction crews to conduct maintenance and repairs. Typically transmission air switches have two different types of interruption devices: line-charge dropping quick-break whips or parallel-breaking vacuum interrupter bottles. In certain scenarios, air switches are also equipped with SCADA controlled or auto-sectionalizing motors so they can be operated automatically or manually so that they can be reset and reused without sending out a person to reset them. (More information on these air switches can be found in Appendix Z on page 103.)

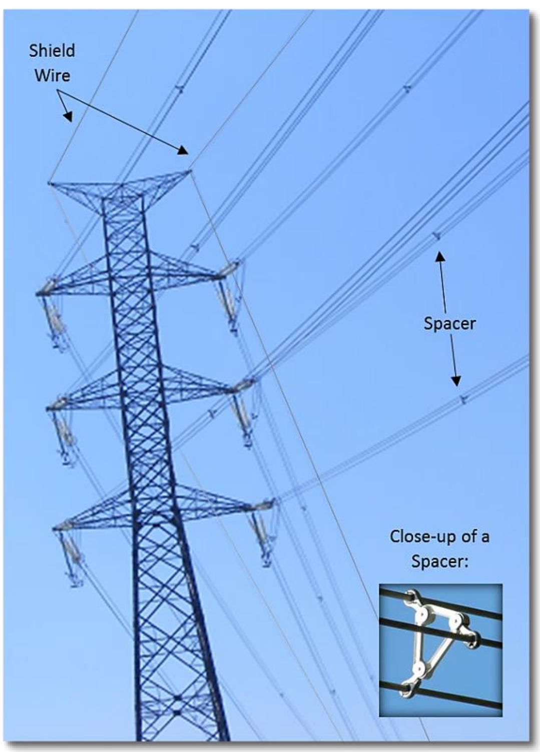
Above: Air Switches mounted on top of a transmission structure



Above: High Speed Whip Air Switch
Below: Bottle Vacuum Air Switch



Shield Wire: Shield wires, also called static wires or earth wires, are usually made of steel and are connected to the top of a transmission structure then grounded to the pole with wires running down to the earth. These wires help protect against lightning strikes. They are typically installed above power lines, as lightning is more likely to strike the shield wire then be routed quickly to the ground. This protects the power lines and equipment by preventing lightning surges from continuing down a power line and into a substation or a customer's home or business. Often optical fibers are embedded in the shield wire,[181] giving it a dual purpose in providing both lightning protection and as a system control and communications path.



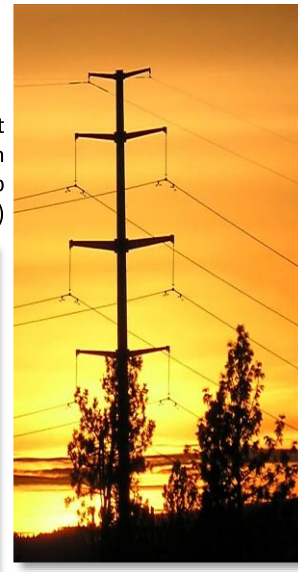
Double Circuit Lattice Tower with three phases on each side and a shield wire on the top cross-arm. Note the spacers separating the conductor strands.

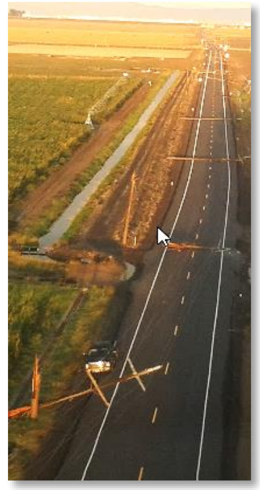
Lightning striking a shield wire

[181] When telecommunications is embedded, it is often called an "optical ground wire" or an "optical fiber composite overhead ground wire."

Spacer: Spacers are often used when multiple conductors are located on the same touchpoint on an insulator. The lines run very closely together making them prone to clashing, twisting, or entwining with each other. The spacer provides adequate gaps between the conductor lines to keep them separated from each other, reducing corona, and helping dampen the effects of wind and the resulting vibration on the lines.

Right: Double Circuit Transmission Line (with ground wire on the top cross arms)





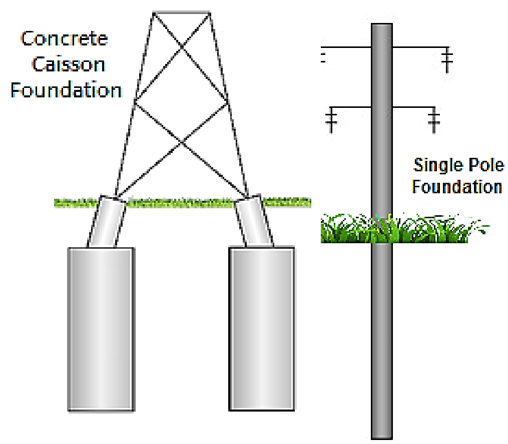
Left: The failure of one pole can create enough tension to cause a whole section of line to fail. (Photo taken in Othello)

Above: Single Circuit Transmission Lines with the traditional three phase conductor

Single Circuit: Single circuit lines contain three electrical phases, one conductor per phase, running from the generating source to the substation.

Double Circuit: A double circuit provides a single path for two circuits on one physical right-of-way, reducing the costs and the footprint associated with installing two separate lines. However, this configuration is more expensive, generally requires a more robust structure, and also increases the risk of loss, as both circuits are exposed to the same potential physical hazards.

Foundation: The base of the transmission pole is critical. It must be designed to withstand the weight of the tower or pole and all of the associated conductor and equipment as well as tolerate the uplift and lateral forces from wind and weather. The foundation is so critical that it can comprise 10% to 30% of the cost to construct a transmission tower.[182] The value of foundations is of tremendous importance in providing stability for the entire transmission line. The loss of one pole can cause the entire line to fail. Designing a foundation includes consideration of many factors including: soil conditions, geographic location (hillside, river crossing, farmland), water and ground water conditions, area weather patterns, type of pole/structure and supporting equipment, potential corrosion issues, etc.



Traditional Direct Embed Transmission Foundations

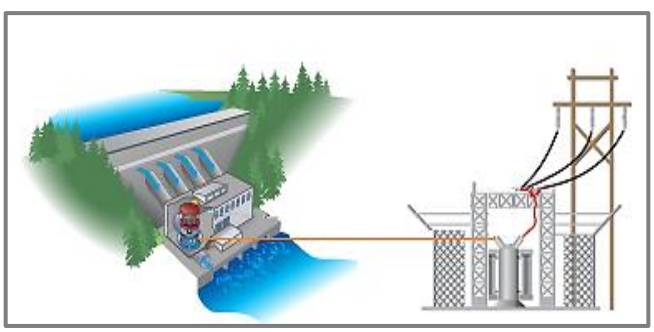
[182] Freeman Thompson et al, "Integration of Optimum, High Voltage Transmission Line Foundations," 2009, http://cruxsub.com/core/files/cruxsub/papers/c6988e90fb75df65fa9a4603809f6286.pdf, page 3.

Transformers: Only three percent of all substation transformers are high voltage, but these transformers carry 60%-70% of the nation's electricity.[183] This critical piece of equipment provides an important link in moving power from the generator to the customer, managing all of the transformations the electricity must make in order to arrive at its destination in a useful form. Power must be reduced from hundreds of thousands of volts to only 110 volts in order to be used by the average household appliance. In order to do this, step-up transformers are used to increase the voltage from the generator[184] to high voltage transmission level[185] in order to move the long distances to reach a substation near a load source. At the substation, the energy enters a step-down transformer to transition to the distribution system voltage level. Transformers are used again at the customer load site to reduce the distribution-level energy to a level that customers can use.

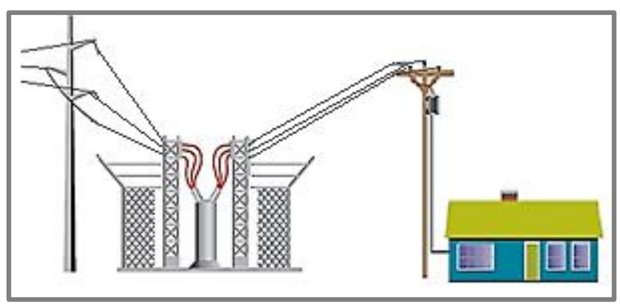
This is one of the largest transformers we purchase. It connects the 230 kV and 115 kV systems.

Transformers in Nez Perce Substation

As an example, electricity is generated at 14.4 kV at Noxon Rapids Dam, then stepped up to 230 kV at the generator step-up transformer located at the power plant in order to jump on to the Noxon-Pine Creek transmission line. On that line, it travels to a centralized substation where it is reduced to 115 kV and travels on to a Coeur d'Alene distribution substation. At that point a transformer decreases the voltage of 13.2 kV. The electricity is delivered at



Generator to Transmission Substation Step-Up Transformer, then Step-Up Transformer to Transmission Line



Left to Right: Transmission Line to Distribution Substation Step-Down Transformer, then Step-Down Transformer to Distribution System, then to Customer Transformer, then to Customer

183 Paul Parfomak, "Physical Security of the U.S. Power Grid: High-Voltage Transformer Substations," Report to Congress, 2014, https://fas.org/sgp/crs/homesec/R43604.pdf, summary page.
184 It is cheaper and more efficient to generate at low voltage then step it up to transmission level, so most power plants are designed to run at around 11 kV. "Why Generator Voltage is 11 kV 50Hz o 13.8 kV 60 Hz," http://www.gohz.com/why-generator-voltage-is-11kv-50hz-or-138kv-60hz
185 Voltage is stepped up to 60 kV, 115 kV and 230 kV for Avista, up to 765 kV in the United States. China is proposing 800 kV; India is proposing a 1200 kV line.

13.2 kV throughout the Coeur d'Alene area until it gets to a customer's house, where it passes through a distribution transformer and reaches its final voltage of 240 V/120 V. The electricity then enters the customer's house where it energizes the electric panel and can be used for everyday devices.

Transmission Substations: As mentioned above, transformers modify electric energy voltage levels. Transmission transformers are usually located in one of the following two types of substations:

1) A **step-up substation** receives power from a generator and uses a transformer to increase the voltage to a high enough level that it can be transmitted long distance across transmission lines.
2) A **step-down substation** can connect different parts of the grid as well as being a place where transmission-level voltage is converted to sub-transmission voltage which is then transferred to the distribution system. These types of substations can also be tapped as a source of energy for industrial customers.

Typical Avista Transmission Substation

Substations are the heart of the power system. They are required for the safe and reliable operation of the system, and are the physical locations to remotely monitor and control the system. They are also a key component for equipment protection, switching for outage management, and isolating circuits for maintenance or to reduce the number of customers impacted by an outage.

Right of Way: Every transmission line has a corridor that provides a safety margin between the transmission lines and surrounding vegetation and structures. These areas are set aside specifically to accommodate the line, and are typically cleared of vegetation or planted with low height vegetation. These areas are carefully monitored to ensure that vegetation, buildings, or other elements do not impose upon the line, creating potential safety issues or outages. The corridor may also contain an access road to allow repair and inspection of the line. The width of a right-of-way varies depending on the voltage level of the line, but is typically from 50 to 175 feet.

Above: Nicely trimmed right-of-way running down the valley for the Noxon – Pine Creek 230 kV line.

Right: Right-of-Way on Addy – Devils Gap showing access road.

Appendix Z: Transmission Glossary of Terms

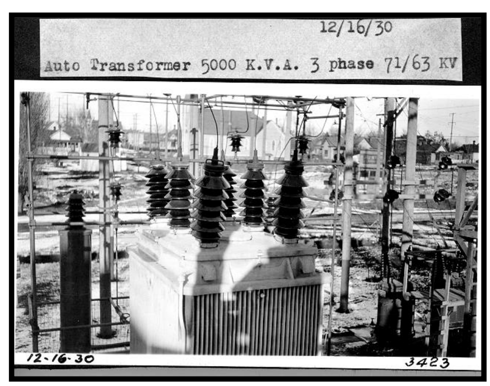
Active Power (or Generation) Control (AGC) Because there are many generators supplying power into the interconnected system, there has to be a means of allocating any changes in demands and required generation across the entire grid so loads and generation always remain precisely balanced and no one generator or utility has to make up the entire deviation. This balance is measured using system frequency. To stay perfectly in balance and keep the frequency level stable, automatic generation control is used to allow the system to adjust multiple generators at different power plants around the grid at exactly the same time, keeping the system perfectly in balance and the generators producing precisely what is needed.

Air Break Switch is a high voltage breaker designed for automatic and controllable high speed interruption of faults on a line. It uses compressed air to open the contacts and quench any arcs.

Ancillary Service These are services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (From FERC order 888-A.[186])

Area Control Error (ACE) is the instantaneous difference between a Balancing Authority's net *actual* and net *scheduled* interchange, taking into account the effects of frequency bias and correction for meter error. Area Control Error occurs when scheduled and actual generation within a control area don't match, which can place an undue burden on other utilities as well as cause unnecessary generator control movements.

Area Interchange Methodology In order to make sure that the interconnected system is not over-subscribed, a simulation was developed that determines how much total capacity (Total Transfer Capability or TTC) is available on the system, then the Capacity Benefit Margin, Transmission Reliability Margin, and existing transmission commitments such as serving native load or existing contracts with other utilities are all deducted, and counterflows are added back in, leaving the space that is actually available to move power on the lines.



Auto Transformer in 1930

Auto Transformer Has only one winding around a laminated core versus a regular transformer, which has two windings, a primary and a secondary, which are not connected. When an auto transformer is under load, part of the load current is obtained from the supply and the rest is from the transformer itself, so it works as a voltage regulator. The voltage can be stepped up or stepped down just by reversing the connections. Since there is only one winding, it contains less copper so it is less expensive. These transformers tend to be smaller and more

[186] United States of America Federal Energy Regulatory Commission, 18 CFR Part 35, https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8p1-000.txt

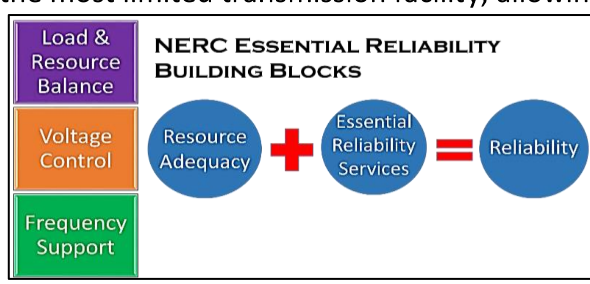
efficient as well as being more effective at voltage regulation. However, there is no insulation between the primary and secondary since both are wound around the same core, so it cannot be safely used in situations where there is a variation in the voltage, like transforming transmission level to distribution level voltage. If there is an issue and high voltage crosses to the low voltage side, the equipment can be significantly damaged.

Today's auto transformer - the Pine Creek Auto Transformer being moved into position

Automatic Generation Control (AGC) This is also called Active Power Control. The interconnected system requires adjusting multiple generators at the same time in response to changes in load across the system. AGC equipment allows this to happen automatically without operator intervention. This insures that the system stays completely in balance.

Available Transfer Capability (ATC) This is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments, including retail customer service, less a Capacity Benefit Margin, less a Transmission Reliability Margin. Basically ATC is a function of how much unused capacity is available on the most limited transmission facility, allowing for a single and sometimes multiple contingencies.

Balancing Authority (BA) The BA is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.



Balancing Authority Area The actual operation of the electric system is managed by entities called Balancing Authorities. Most, but not all, balancing authorities are electric utilities that have taken on the balancing responsibilities for a specific portion of the power system, the area of their responsibility. The Balancing Authority maintains load-resource balance within that specific area, ensuring in real time that the power system supply and demand are perfectly matched.

Bulk Electric System This includes transmission lines, interconnections with neighboring systems, and associated equipment that is operated at voltages of 100 kV or higher, or generation resources above 20 MVA. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.[187]

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[187] Cynthia S. Bogorad and Latif M. Nurani, "NERC's Definition of the Bulk Electric System," http://www.spiegelmcd.com/files/APPA_Legal_Seminar_Paper_NERC_BES_2012_10_25_09_08_51.pdf

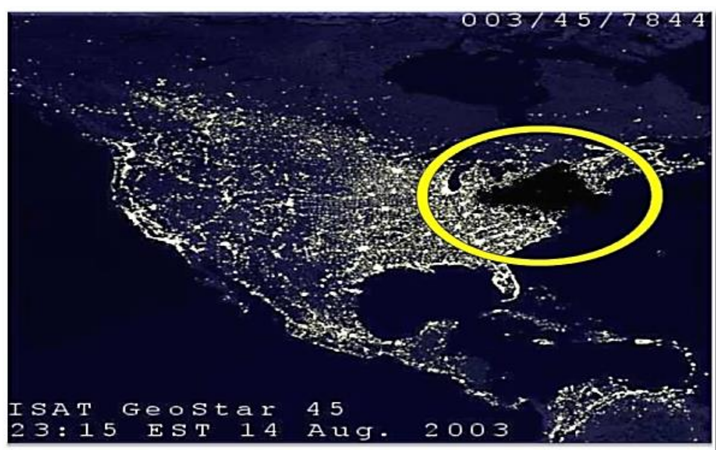
Bulk-Power System This includes all facilities and control systems necessary for operating an interconnected electric transmission network (or any part of it) as well as the electric energy from generation facilities needed to maintain transmission system reliability. These are facilities that, if disrupted, would impact the grid beyond just one location. The difference between the "Bulk Power System" and the "Bulk Electric System" is that, in the former, facilities do not have a minimum voltage requirement.

Capacity Allocation The transfer capacity of a path is allocated among the rights-holders on that path based on their negotiated agreements unless impacted by system operating conditions such as emergencies that reduce the capacity of the line. This transfer capacity becomes a right that the holder may use for their own loads or sell to others.

Capacity Benefit Margin (CBM) is the amount of Total Transmission Capacity (TTC) held back by energy providers to allow for importing generation (thanks to their interconnections) to meet generation reliability requirements *if they face a generation loss*. Reservation of CBM by a load-serving entity allows them to reduce their own generating capacity because they have interconnections available to help them meet load requirements if they get in a bind. However, CBM is, in essence, a last resort and can only be called upon when all non-firm sales have been terminated, direct load management has been implemented, and all interruptible customers have been interrupted.

Capacity Emergency A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand and it's regulating requirements.

Capacity Margin Formula = (Available Resources – Peak Firm Load) / Available Resources

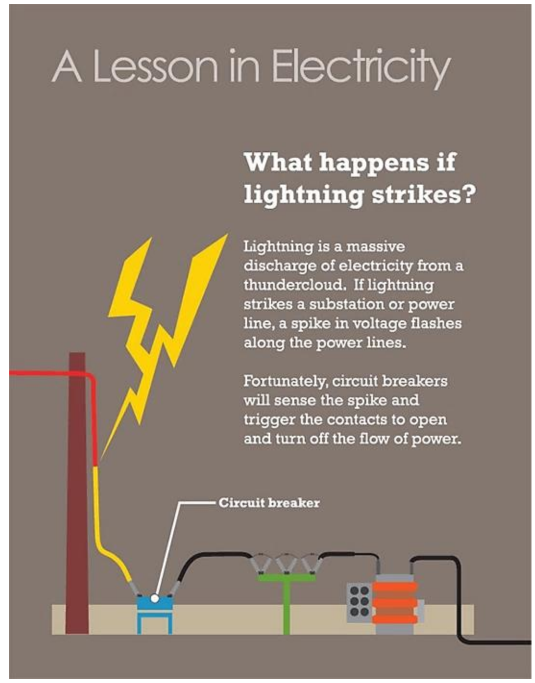


Cascading Outage in the Northeast in 2003

Cascading Outage The uncontrolled successive loss of system elements triggered by an incident at any location can cause a cascading outage that rolls across several sections or the entire interconnection. Usually there is one or more initiating events, such as heavy loading on a line due to high temperatures and heavy loads in conjunction with the line sagging into a tree. The line fails, which shifts the load it was carrying to other interconnected lines, overloading them, and triggering cascading events in widespread electric service interruption that reaches a point where it cannot be stopped from spreading beyond the area in which it started.

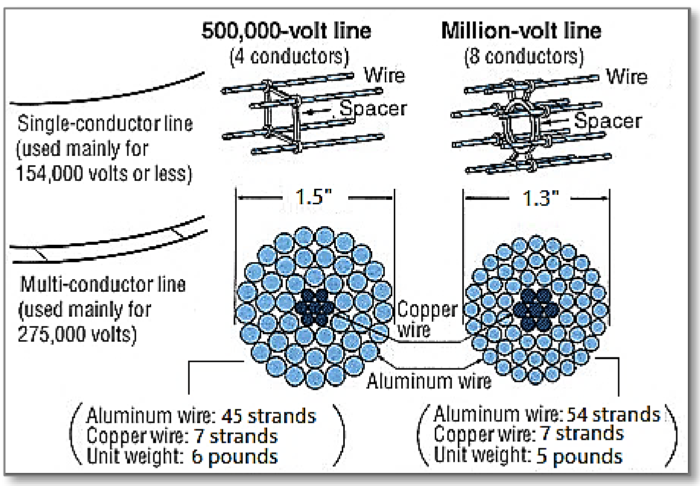

Circuit Breaker

Circuit Breaker is an essential device usually located in a substation for interrupting excessive current flow typically initiated by a fault or heavy loading. Circuit breakers cut the power until someone can fix the problem. In addition, using a circuit breaker, interruption and reclosing times can be adjusted to keep temporary faults from resulting in a sustained outage. The circuit breaker can sense whether the fault is transient and choose to keep the electricity flowing. If it is a serious fault that must be addressed, the breaker halts the flow.



Confirmed Interchange happens when the transmission owner and the entity that wishes to purchase transmission rights have come to agreement; no involved party has issues with the contract and all required parties have approved the Arranged Interchange.

Conductor The physical line that carries electricity from one place to another. It must be very durable and conductive as well as being light weight, so is typically made of aluminum with a steel or copper core.[188]

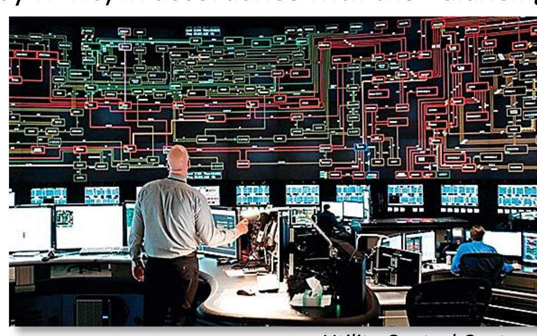


Consequential Load Loss This includes all load that is no longer served by the transmission system as a result of transmission facilities being removed from service or tripped by a protection system operation designed to isolate the fault.

Contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element or the loss of energy being imported. It is basically anything that causes an unexpected imbalance between generation and loads in the interconnected system.[189]

Contingency Reserve is capacity that has been set aside by the Balancing Authority so they can respond to a system emergency (an emergency as defined by NERC) in accordance with the Balancing Authority's Emergency Operating Plan. These reserves must be available in a very short period of time so the system can respond when an event disrupts the power supply.

Control Center The control center may be one or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time, performing reliability tasks. It also includes associated



Utility Control Center

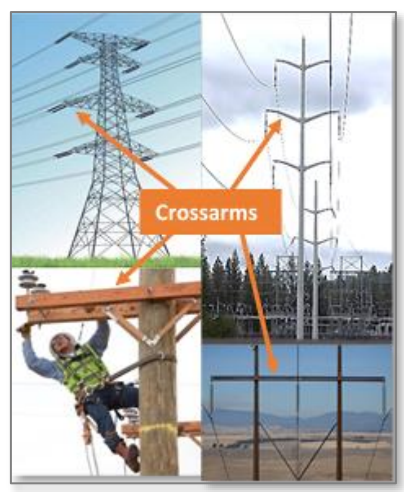
[188] Conductor illustration courtesy of Tokyo Electric Power Company, https://www4.tepco.co.jp/en/corpinfo/ir/kojin/supply/transmission-e.html
[189] NERC glossary of terms: http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

data centers of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission facilities at two or more locations, and/or 4) a Generator Operator for generation facilities at two or more locations.

Corona All electric transmission lines can generate a small amount of sound energy as a result of corona. This happens under certain conditions when the localized electric field near energized components and conductors produces a tiny electric discharge, called corona. This causes the surrounding air molecules to ionize or undergo a slight change of electric charge. Utilities try to reduce the amount of corona because, in addition to the low levels of noise that it creates, corona creates power loss, and in extreme cases it can damage system components over time. It becomes more noticeable at higher voltages (345 kV and higher) and during wet and humid conditions as water drops collect on the conductors and increase corona activity. Under these conditions, a crackling or humming sound may be heard in the immediate vicinity of the line. In fair weather conditions, the audible noise from corona is minor and rarely noticed. To reduce corona, utilities bundle the conductor to make the diameter of the line larger, which reduces corona, resistance and thus losses. They also work to eliminate any sharp points where electric charges tend to form.

Corona Effect

Counterflows Electricity is bought and sold using scheduled delivery routes. However, the electricity itself follows routes ordained by the laws of physics, which are not necessarily identical to the paths set by the buyers, the sellers, or the operators of the grid. When the actual electricity path differs from the routes it is scheduled to be on, the difference is known as counterflow or "loop flow." Loop flows occur in all interconnected transmission systems as the flow of electricity follows physical laws across the continent. Loop flows can incur unnecessary costs, impacting lines not associated with the schedule and changing their load levels, potentially leading to overloads on "innocent" lines.



Corrective Action Plan This is a list of actions and an associated timetable for implementation to remedy a specific problem. In some situations these are mandated by NERC.

Critical Assets include facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.

Crossarm A crossarm is a piece of hardware providing an attachment point for insulators to support the loading of overhead conductors. The crossarm is typically made of wood, steel or fiberglass.

Curtailability The transmission provider has the right to interrupt all or part of a transmission service due to constraints that reduce the ability of the network to provide that service. This is called curtailability.

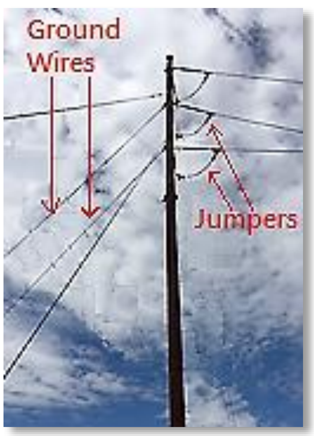
Curtailment is a reduction in the output of a generator from what it could otherwise produce given its available resources, typically on an involuntary basis. It can also refer to a reduction in the amount of scheduled capacity or energy delivery on a transmission path, typically due to unexpected circumstances or as agreed upon by both parties to the contract. As an example, a utility may have an interruptible customer that has agreed to power reductions if loads reach a certain level in exchange for a reduced rate.

Cutout is a "C" shaped piece of insulated hardware with a tubular insulator that is designed to melt or break when the circuit through it exceeds its rated value. This serves to disconnect one section of the line from another section of the line for maintenance or repair or to prevent an outage from spreading.

Cutout

Cyber Assets include programmable electronic devices and communication networks, hardware, software, and data that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, mis-operation, or non-operation, adversely impact the reliable operation of the Bulk Electric System.

Cyber Security Incident Any malicious act or suspicious event that compromises, attempts to compromise, or disrupts the electronic or physical security perimeter of a Critical Asset is considered a cyber security incident.

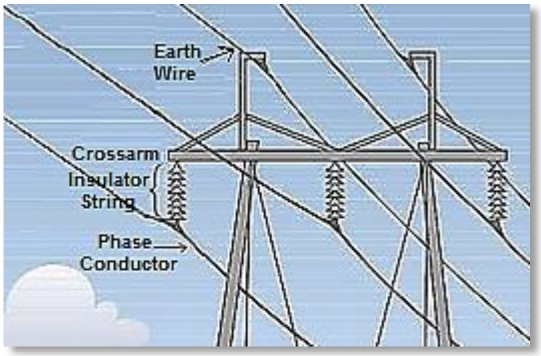


Above and right: Dead End Structures

Dead End Structure is a distribution or transmission pole where the tension of an overhead line is terminated. Conductor and ground wires are pulled only on one side unless it is a double dead-end, where an overhead line in both directions is terminated. With a double dead-end the conductor is pulled by ground wires in two directions to insure adequate support. Jumpers can be used to connect each end of the conductor so the line can continue. Dead ends are often used where lines end, turn at a large angle, are at a major crossing like a river or highway, or where a line will be divided into sections. These structures help alleviate the added tension and stresses caused by these conditions and reinforce the line.

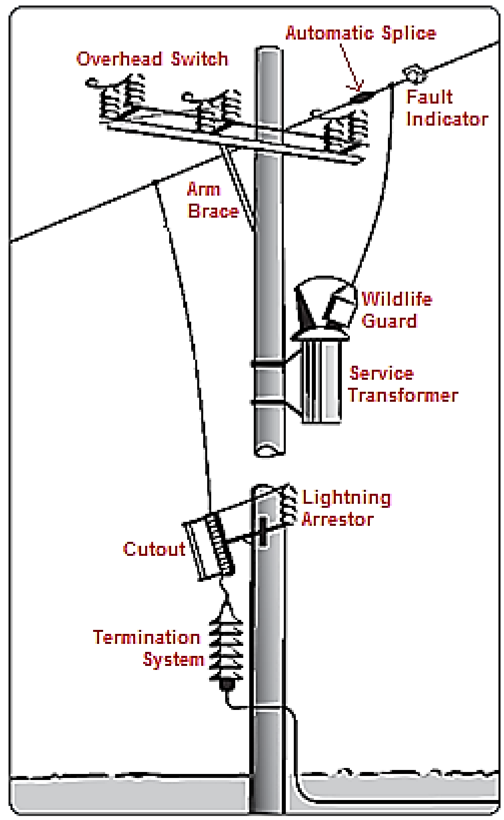
Disturbance is defined as either: 1) An unplanned event that produces an abnormal system condition; 2) Any agitation to the electrical system; or 3) The sudden failure of generation or interruption of load.

Dynamic Interchange Schedule or Dynamic Schedule This is a time-varying energy transfer that is updated in real-time and used as a schedule for accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area, especially if the utility wants to use its remote generation for Automatic Generation Control (AGC) or for serving loads in a different control area. This type of schedule is used to transfer Colstrip energy in Montana to Avista customers in Washington. It is also used when the host control area cannot tolerate significant differences between schedules and actuals.



Earth Wire: This is also called a static wire. It is a low-resistance ground wire connected to the earth or buried in the ground. It is located above the transmission conductor so that lightning is more likely to strike the earth wire and the resulting current flows into the ground rather than across the transmission line to the substation. Thus it is designed to help protect electrical equipment.

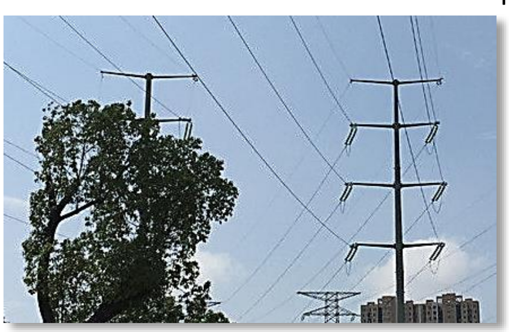
Emergency Operating Plan establishes the criteria to be followed in the event of an Extraordinary Contingency, which is an event that causes a significant frequency deviation, capacity or energy deficiency, unacceptable voltage levels, or other system emergency.[190]



Energy Emergency is a condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected load obligations.

Extraordinary Contingency includes any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed.

Fault A fault is an abnormal condition present on the power system, usually a short circuit caused by lightning, tree contact, windblown object in the lines, or other similar problem.



Anyone see a problem here?
Note: This is not on Avista's System!

Firm Load is the electric power that is guaranteed by the utility to be available except when uncontrollable forces create an outage. This load includes the utility's own customers.

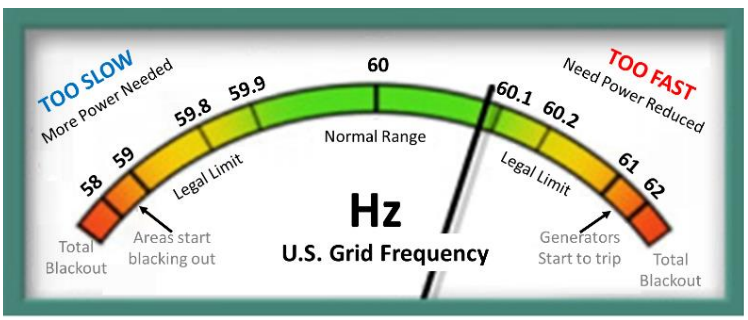
Firm Transmission Service is the highest quality or priority service offered to customers under a filed rate schedule that anticipates no planned interruption. Typically all other contracts are cut before a firm contract is cut.

190 Avista's Emergency Operating Plan is overseen by Peak Reliability. https://www.peakrc.com/_layouts/download.aspx?SourceUrl=/RCDocs/Emergency%20Operations%20Procedure%20v6.0.pdf

Flowgate The boundary between two parts of a transmission system that may be congested is called a flowgate. At this point there is a limitation in the amount of power allowed or able to flow across that boundary.

Forced Outage Typically a forced outage is either the removal from service availability of a generating unit, transmission line, or other facility for emergency reasons, or the condition in which the equipment is unavailable due to unanticipated failure.

Frequency Generators connected to the grid function as a team, synchronized with each other. The key common denominator between them is frequency, which is the change in direction in current flow in an alternating current (AC) system. In the U.S., the grid frequency is 60 Hertz (cycles per second). This frequency is directly linked to the speed of the rotation of the generators. The frequency varies constantly, usually in a very small range of +/- .5 Hertz or less. Governors control the speed of individual generators to help them stay at 60 Hertz. As the load on the grid increases, generators tend to slow down, so the governors compensate by pushing the generators into increasing their speed to maintain the frequency. If a generator cannot increase its speed, another one on the grid will compensate by increasing its speed. When all of the generators on the grid have reached their maximum ability to compensate, the grid will operate at a frequency less than 60 Hertz, indicating that the grid is overloaded and demand must be reduced.



Frequency Bias The Balancing Authority is responsible to provide or absorb fluctuations in the frequency of the interconnected grid in order to keep the frequency stable. For example, if frequency goes low, each Balancing Authority is asked to contribute a small amount of extra generation in proportion to its system's established bias, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz). Each Balancing Authority uses common meters on the tie-lines with its neighbors for control and accounting of how much they contribute to keeping the grid stable. These meters insure that this extra generation or reduced generation is distributed fairly.[191]

Frequency Bias Setting is a value, usually expressed in MW/0.1 Hertz, set into a Balancing Authority Area Control Error calculation that allows the Balancing Authority to contribute its frequency response to the Interconnection and do its fair share of keeping the grid frequency stable.

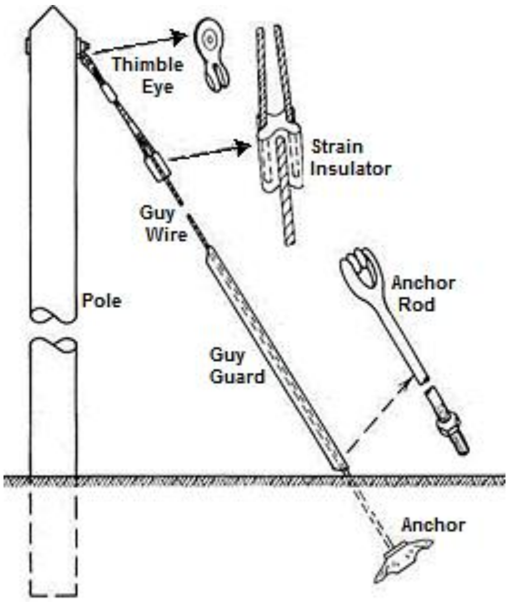
Frequency Deviation is a change in interconnection frequency, usually managed by the automatic response of generating units (using AGC) across the grid, increasing or decreasing output to keep the frequency stable.

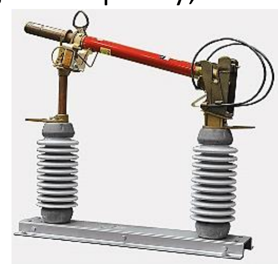
Frequency Error is the difference between the actual and scheduled frequency.

Frequency Response is the ability of a system or elements of the system to react or respond to a change in system frequency following the sudden loss of generation or load, and is a critical

[191] For more information on this, see: NERC Frequency Control, http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

component, particularly during disturbances and recoveries. Frequency response is predominately provided by the automatic and autonomous actions of turbine governors. Failure to maintain frequency can disrupt the operation of equipment and initiate disconnection of power plant equipment to prevent it from being damaged, which could lead to widespread blackouts. Frequency is the sum of change in demand plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz.

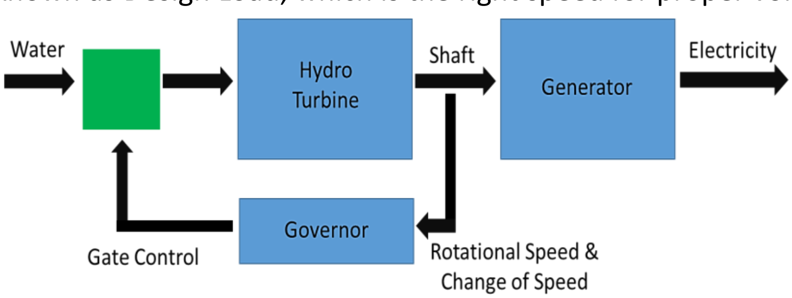



Fuse

Fuse (or junction fuse) is a device that limits the amount of current flowing through the circuit. The fuse is constructed with a small piece of metal that, when exposed to high current typically caused by a fault, melts and interrupts the flow of electricity. Fuses are typically placed on lateral tap lines off the main circuit.

Guy wire is a non-energized wire connected from a distribution or transmission pole to an anchor in the ground to offset the tension of overhead conductors. A guy wire is typically found on a dead-end structure or side-angle structure. On a dead-end structure the entire tension of the conductor is offset by a guy wire. If the guy wire is struck by a vehicle or other object and damaged, the tension of the overhead conductor, without proper support of the guy wire, can break the pole.

Governors These devices control the speed of individual generators to help them stay at 60 Hertz. When the load on the generator increases, it causes the generator to work harder. Without a governor, the generator slows down, *lowering* both voltage and frequency. Likewise, when the load on the generator is reduced, the generator speeds up, *raising* voltage and frequency. With no load whatsoever, the generator would "freewheel," and run at a very high speed, likely causing damage. The governor constantly monitors voltage and frequency, adding or subtracting electrical loads as needed to compensate for human usage and helping the generator stay at exactly the "perfect" load, known as Design Load, which is the right speed for proper voltage and frequency. If one generator attached to the grid cannot increase its speed, another one on the grid will compensate by increasing its speed via a governor to keep the grid in perfect balance.



Ice loading During the winter, ice forms from moisture that accumulates on overhead conductors. This accumulation of ice causes increased stress and tension on both the conductor and the supporting structures. This added stress can result in the breaking of either the support structure or the overhead conductor. Under certain conditions, the formation of the ice will act as an air foil. The ice air foil is similar to an airplane wing and can cause the overhead conductors to oscillate or "gallop," adding further strain.

Snow & ice loading in Reardon breaks conductor and shatters a pole

Implemented Interchange This occurs when the Balancing Authority enters the amount of the agreed-upon transmission contract capacity into its Area Control Error equation so it is officially part of the capacity posted on OASIS for a line.

Inadvertent Interchange happens when more energy passes through a system than has been agreed upon. It is the difference between the Balancing Authority's Net *Actual* Interchange and Net *Scheduled* Interchange.

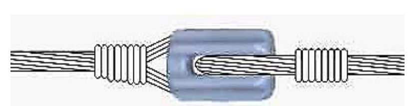
Interruptible Load Some utility customers, typically large industrial or commercial customers, have an arrangement with the utility to allow their load to be reduced or cut based upon specific, typically adverse, conditions such as extreme weather. Businesses that can afford to have their services interrupted or that can significantly reduce their consumption when notified by the utility can get better rates by having non-firm service/interruptible load, so it is an attractive option for the customer but also for the utility, which can use this interruptible load as a resource.

Insulator Insulators have the duty of keeping the electrically charged transmission line from touching the poles or towers so the line can continue to transmit and is not grounded.

Strings of transmission insulators, sometimes called bells

Insulators must be strong enough to withstand the weight of the conductor and the potential stress of the electricity wanting to connect to the earth. They are designed to be non-conducting, but getting wet can cause flashovers, which is why many insulators are designed with an umbrella or petticoat at the top to keep the lower part insulated from the rain.[192] Extreme weather, sun and vandalism can reduce the strength of the insulator, making it more likely to break and cause an outage so insulators are monitored during inspections. There are many kinds of insulators depending upon their application, including the most common:

Insulator with pin



Stay Insulator

Dead-end Insulator

[192] For more than you ever wanted to know about insulators, see: https://www.insulators.info/general/glossary/


Post Insulator

1) Pin Insulator: is mounted on an insulator pin, typically made of glass, porcelain or composite polymer and is the insulating property between the energized conductor and the crossarm.
2) Post insulator: bolts directly to the pole or crossarm and does not require an insulator pin.
3) Dead-end insulator: is designed to handle the tension of an overhead conductor when it is terminated at a pole.
4) Guy strain or stay insulator: is inserted into a guy wire to prevent the guy wire from becoming energized. These insulators are typically made from a polymer or fiberglass material.


Jumper Conductor

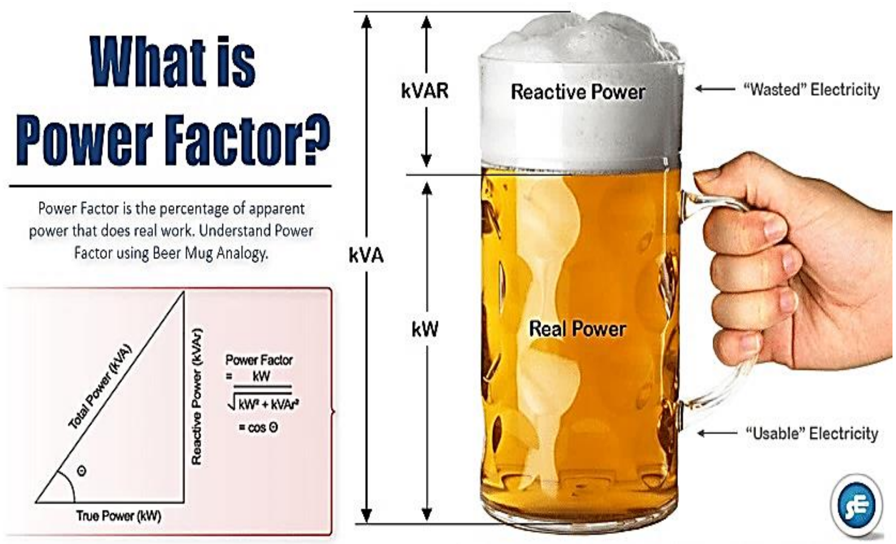
Insulator pin This is a piece of overhead hardware that fastens the insulator to the crossarm. The insulator pin is bolted through the crossarm and the insulator is screwed onto the top of the insulator pin.

Interchange is the energy transfers that cross Balancing Authority boundaries.

Interchange Authority is the responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of information for reliability assessment purposes.

Islanding This happens when a Balancing Area or portion of one is isolated from the grid. Usually this is unintentional, but occasionally a utility will island from the grid to prevent a cascading outage.

Jumper Conductor connects two ends of a conductor/line when the line is interrupted at a pole such as when it makes a corner and the tension of the corner requires the line to be directly connected to the pole for additional strength.



kV is 1,000 volts or kilovolts.

kVA Also called apparent power, this is the sum of kVAR and KW. In the analogy on the right, this is the total contents of the mug including both the beer and the foam.

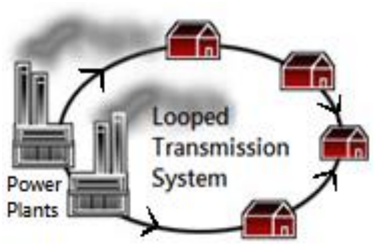
kVAR Also called reactive power or wasted power, this is the power that magnetic based equipment such as transformers, motors, and relays need to run. It is also the portion of electricity that establishes and sustains the electric field of AC equipment. It is essential in transferring power across transmission lines. In the beer analogy, this is the foam part. It is a necessary "part of the beer experience but it does not quench a thirst."

kW is a thousand watts. Also called working power, actual power or real power because it is the part of power that actually powers equipment and performs useful work. In the analogy above, it is the actual beer part.

Lightning arrester is a piece of hardware that reduces voltage surges from direct or nearby lightning strikes. When a lighting strike occurs, the overhead conductor experiences higher than normal voltage levels. This high voltage is dissipated into the lighting arrester, mitigating potential damage to equipment.

Long Term Transmission Planning Horizon This is the time period that covers years 6 to 10 and beyond.

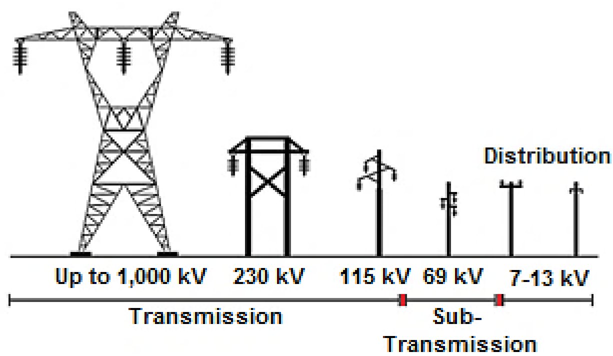
Looped refers to a transmission or distribution line that has a redundant feed; it provides options to serve a customer via a different line or direction if one line fails.



Misoperation This occurs when a protection system does not operate with its specified time period or it does not stop a fault or other abnormal condition within its area of control. It can also occur if the protection system operates when it is not supposed to do so.

Most Severe Single Contingency is that single contingency which results in the most adverse system performance under any operating condition or anticipated mode of operation.

Multiple Contingency Outages is the loss of two or more system elements caused by unrelated events or by a single low probability event occurring within a time interval too short, less than ten minutes, to permit system adjustment in response to any of the losses.

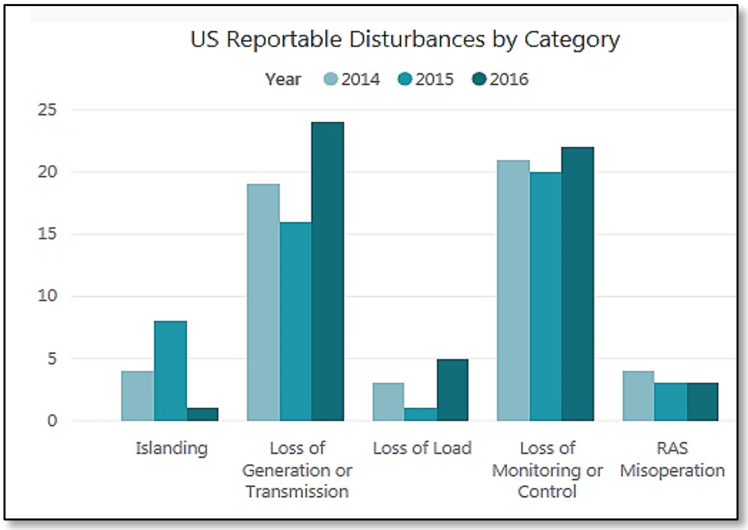


Native Load means the end-use customer load of a utility.

Near Term Transmission Planning Horizon is the time period that covers 1 to 5 years.

Non-Consequential Load Loss This tends to be a controversial term, as the industry and the NERC could not agree upon what constitutes "non-consequential" so there are still some ambiguities. The NERC definition is basically that "Non-Consequential" is anything **not** "consequential," which means load tripped off when transmission facility protection systems operate to isolate a fault, loads tripped off due to voltage sensitivity, or load that is disconnected or tripped from the System by the customer or their equipment.

Non-Firm Transmission Service Non-firm transmission service is reserved on an as-available basis and is subject to curtailment or interruption. This tends to be the first thing utilities cut when they experience system contingencies.



Courtesy of Western Electricity Coordinating Council
https://www.wecc.biz/epubs/StateOfTheInterconnection/Pages/Events-Outages/Disturbances.aspx

Non-Spinning Reserve is a generating unit not connected to the system but capable of serving demand within a specified time. It can also be interruptible load that can be removed from the system within a specified time.

Reportable Disturbance Any event that causes area control error changes greater than or equal to 80% of a Balancing Authority's or Reserve Sharing Group's most severe contingency is considered reportable. These events include: islanding, loss of three or more Bulk Electric System facilities from a common cause, any loss greater than 2,000 megawatts of generation, loss of more than 200 megawatts of firm load for 15 minutes or more, loss of the ability to monitor or control operations for 30 minutes or more, or failure/mis-operation of a Remedial Action Scheme.

Open Access Same Time Information Service (OASIS) This is an electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously. Used to make reservations on a utilities transmission system.

Open Access Transmission Tariff (OATT) is an electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission (FERC) requiring a Transmission Service Provider to furnish all transmission service purchasers with non-discriminating service comparable to that provided by Transmission Owners to themselves and their own customers.

Operating Instruction This is a command by operating personnel responsible for the real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an element or facility of the BES. Note that a discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.

Above: Washington Water Power's First Line Truck early 1900

Left: Linemen stringing the Palouse line in 1930

Operating Procedure is a document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. For example, this may be a document that lists the specific steps for a system operator to take in removing a transmission line from service.

Operating Reserve is the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

Out-of-Step Blocking This is a protection system that can tell the difference between a fault and a power swing. If it is a power swing, the protection system blocks or prevents tripping associated transmission facilities; if it is a fault, the protection system trips the facility to protect it.

Physical Access Control Systems are cyber assets that control, alert, or log access to the physical perimeter of a facility, not including locally mounted hardware or devices such as motion sensors, electronic lock control mechanisms, and badge readers.

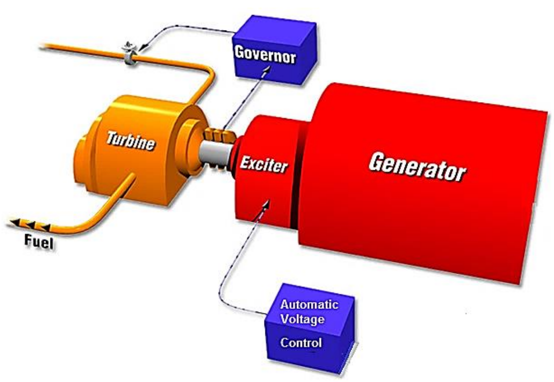
SMUD implemented security measures that led to a tenfold drop in facility intrusions in two years.

Physical Security Perimeter is the physical, completely enclosed border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.

Postback is a positive adjustment to posted available transmission capacity, including processing redirects and unscheduled service.

Power Factor is the percentage of Apparent Power that does real work.

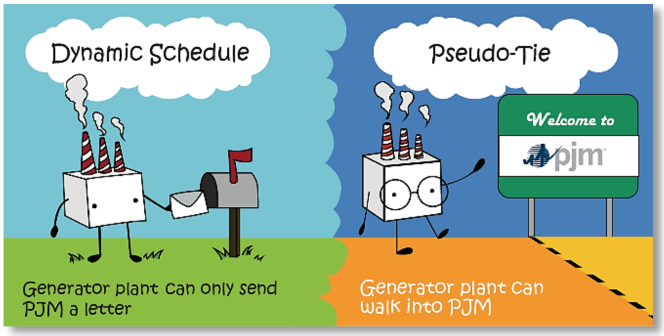
Power System Stabilizer (PSS) These are part of the Automatic Voltage Regulation system of a generator, designed to add or subtract torque to the generator to help dampen oscillations on the grid. Oscillations occur as a result of many machines being connected to one section of the grid and not being exactly in phase with a group of machines on another part of the grid, in essence, creating the potential for the grid to become a giant oscillator. In order to prevent that, system stabilizers are installed on synchronous generators of a size that can mitigate this issue.



Protection System Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry designed to protect equipment and facilities comprise protection systems.

Protective Relays These detect and attempt to correct faults. They read measurements such as current, voltage, and frequency and can be set to recognize when these indicate a problem. For example, if a protective relay senses that a circuit breaker is interrupting the system, it can disconnect it.

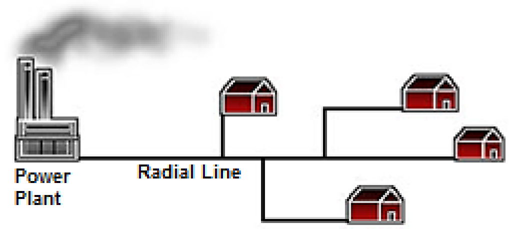
Pseudo-Tie This occurs when two control areas electronically link their Automatic Generation Control (AGC). In this case, the transfer of generation or load is treated as a new point of interconnection (a "pseudo-tie") but there is no actual physical tie or metering. The host control area (for example, for Colstrip it is NorthWestern) can transmit a revised schedule to the other owner(s) such as Avista as load or generation changes, dynamically changing the flow of energy.



A cute depiction of pseudo-tie from PJM Interconnection

Qualified Transfer Paths A transfer path designated as being qualified for unscheduled flow mitigation, where a schedule can be established, actual flow is metered, and a System Operating Limit has been established.

Radial is a transmission or distribution line that does not have a redundant feed – it is a single line running from the generator to the customer, so if this line is lost, customers lose service, versus a redundant system that has another line or lines available to serve load if one line is lost (see Looped or Redundant).



Rated System Path Methodology The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC) determined via modeling and/or simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and postbacks and counterflows are added back in as applicable to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

Reactive Power Measured in kVARs, this is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. It cannot be converted to another form such as light or heat but is essential in transferring power through transmission lines. It creates the oscillation between the generator and the load. Reactive power must be supplied to most types of magnetic-based equipment, such as motors and transformers. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors, and directly influences electric system voltage. It is usually expressed in kilovars (kVAR) or megavars (MVAR).

Real Power is the portion of electricity that supplies energy to the load.

Recallability The right of a transmission provider to interrupt all or part of transmission service for any reason, including economic reasons, as long as it is consistent with FERC policy, associated tariffs, and/or contract provisions is called recallability.

Recloser is a device that operates similarly to a circuit breaker but is installed on a distribution circuit. Reclosers are available for both single-phase and three-phase fault interruptions. The main purpose of a recloser is to sectionalize a portion of a circuit from the rest of the circuit to prevent outages from spreading.

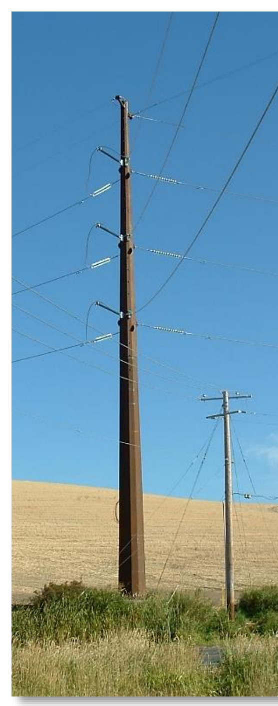
Viper Recloser

Redundant This is also called Looped. In the transmission world, this means that more than one line or route runs between the generation source and the end customer, so if one line is lost, the power is rerouted via another line and the customer suffers either a shorter outage or no outage at all.

Regional Reliability Organization This is an entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. (See Regional Operating Entities on page 74).

Regulating Reserve is an amount of reserve that automatically responds to Automatic Generation Control when a generator trips offline or there is some other disruption to the electricity supply. It can come from a variety of generating resources and is typically a little bit of extra generation from several different generating resources, providing sufficient energy to make up for the lost generation and allow the grid to stay stable.

Reliability Coordinator has the highest level of authority in the Bulk Electric System, responsible for the reliable operation of the grid. The Reliability Coordinator has a wide-area view of the grid as well as the operating tools, processes and procedures to control it, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has a purview that is broad enough to be able to calculate Interconnection Reliability Operating Limits for their entire section of the grid, such as the Western Interconnection, which is based on the operating parameters of many interconnected transmission systems. This is beyond any one Transmission Operator's (such as Avista's) vision. (For more information, see page 78).

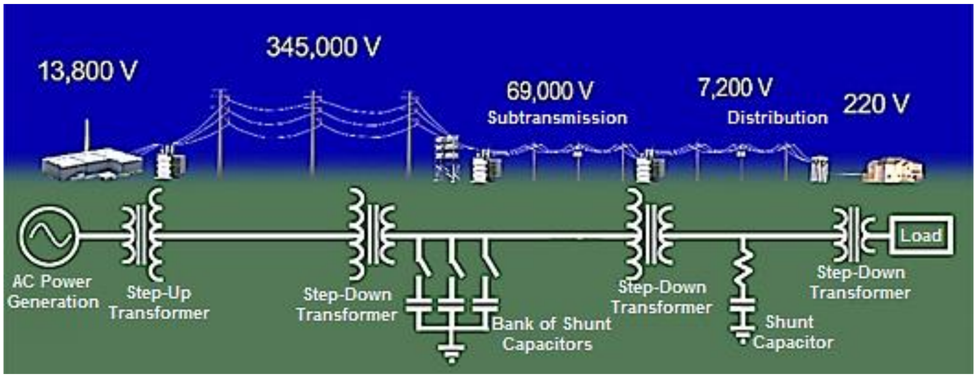


Transmission Pole next to a Distribution Pole

Reliability Coordinator Area is the collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas. For Avista, this is Peak Reliability.

Reliability Standard is a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions (such as Canada), to provide for Reliable Operation of the Bulk

Power System. The term includes requirements for the operation of existing Bulk Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk Power System. The term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.

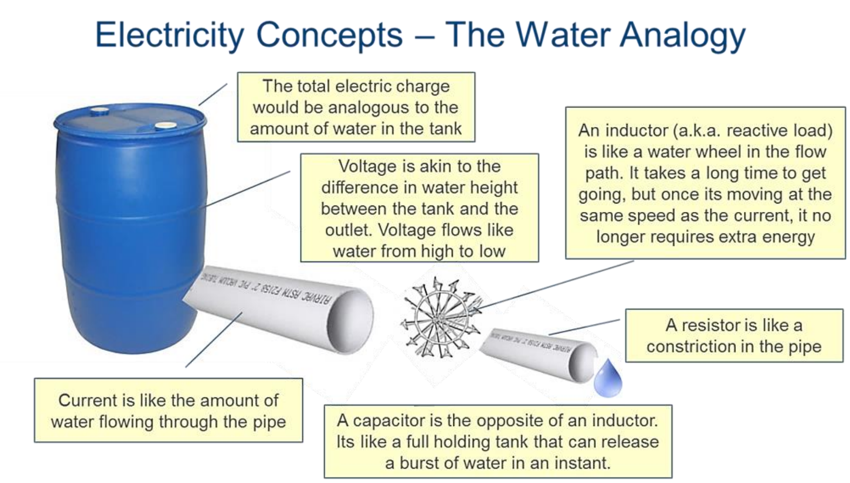


Remedial Action Scheme (RAS) detects predetermined system conditions and automatically takes corrective actions that may include, but are not limited to, adjusting or tripping generation (megawatt and MVAR), tripping load, or reconfiguring a system.

Remote Switching A remote switch is operated from a location other than the substation. These switches are typically monitored, controlled and operated by a dispatcher.

Reportable Cyber Security Incident A cyber security incident that compromises or disrupts one or more reliability tasks of a functional entity must be reported.

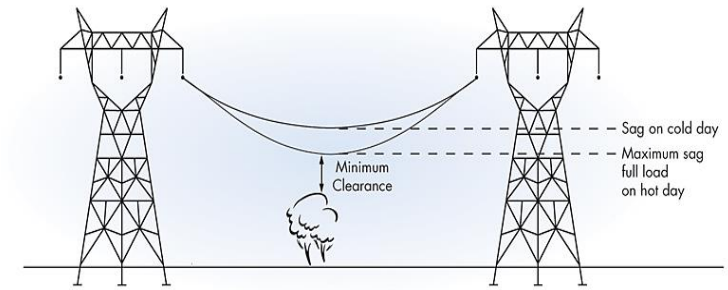
Reportable Disturbance Any event that causes an area control error greater than or equal to 80% of a Balancing Authority's or Reserve Sharing Group's most severe contingency must be reported. The definition of a reportable disturbance is specified by each Regional Reliability Organization, which for Avista is Peak Reliability. Peak defines a reportable disturbance as communication failures, loss of generation, load, or transmission, some types of vandalism and security threats.[193]



Reserve Margin This is generation that is held in reserve above what is expected for peak load demands in case the system faces an unexpected event such as the loss of a generating resource or a transmission line. The formula = (Available Resources – Peak Firm Load) / Peak Firm Load

193 For more detail: https://www.wecc.biz/Reliability/2016%20SOTI%20Final.pdf

Sag For overhead transmission lines, sag is the difference between the point of support, being the transmission pole or tower, and the lowest point on the conductor. Calculating sag is critical, as conductor must be held at a safe tension level to insure that it does not break under its own weight or the added weight of snow and/or ice or as it is stressed by wind, loads, or ambient temperatures. Engineers also carefully calculate the amount of sag to insure that the conductor remains a safe distance from the ground. This is especially tricky when the line is on uneven terrain.

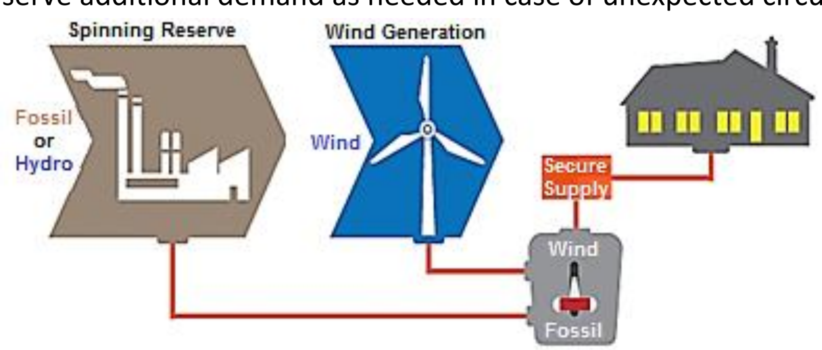


Scheduled Frequency has the goal of 60.0 Hertz, except during a time correction.

Single Contingency is the loss of a single system element under any operating condition or anticipated mode of operation.

Special Protection Systems (SPS) Also called a Remedial Action Scheme (RAS), this is an automatic protection system designed to detect abnormal system conditions and take corrective actions other than isolating a faulted component. Typically this includes changes in generation levels or shedding load. An SPS is a system **not** included as an undervoltage or underfrequency system or out-of-step relaying.

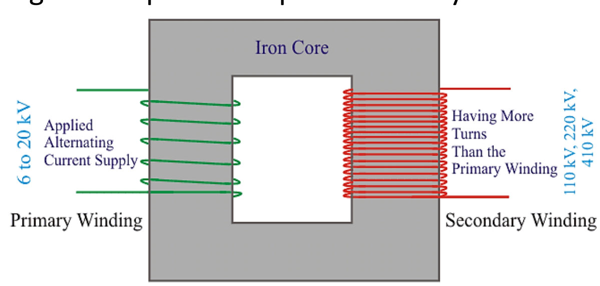
Spinning Reserve Unloaded "extra" generation that is synchronized to the grid and instantly ready to serve additional demand as needed in case of unexpected circumstances is called spinning reserve. Often it is extra capacity available on a generator such as adding extra torque to a turbine's rotor so it can increase its power output. Spinning reserve can also be load that is fully removable from the system (interruptible load) if there is a contingency event.



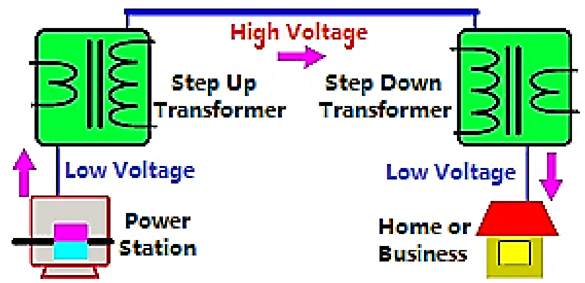
Stability The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances defines that system's stability.

Stability Limit is the maximum power flow possible through some particular point in the system while maintaining stability in the entire system.

Step-Up and Step-Down Transformers In a step-up transformer, the output or secondary voltage is greater than its input or primary voltage. A step-up transformer is used for converting the low voltage produced by a power plant into the high voltage that transmission lines use to move electricity to the



Step Up Transformer

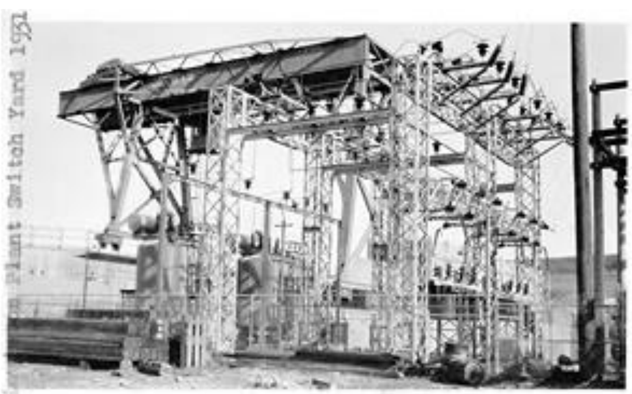


substation. A step-down transformer is the opposite. There are fewer secondary windings than primary windings, so it converts high-voltage, low-current power into low-voltage, high-current power used for customers. A good example of the use of a step-down transformer is a doorbell, which has a step-down transformer to convert the 110 volt household current into the 16 volts the doorbell needs.

Sustained Outage This is the de-energized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.

Switch is a disconnection point used to interrupt the flow of electricity. Switches can be mounted on overhead lines, on underground lines and in substations. Switches mounted overhead and underground are used as a disconnection point as well as a sectionalizing device. During outages the switch can be opened in order to sectionalize the faulted or damaged part of the circuit. Switches mounted in a substation can be used to isolate devices in a substation, such as a regulator, to protect them in case of fault.

Above: Air Switch in open position
Right: Air switches waiting to be installed



Lewiston Switch Yard in 1931

Switching Station (or Switchyard) This is a substation that does not have any transformers, but operates at a single voltage level. It is used for connecting and disconnecting transmission lines. It is also used to isolate faulty portions of a line very quickly, keeping the grid stable.

Switchgear This is a combination of electrical switches, fuses or circuit breakers along with control systems such as transformers, relays, and circuitry used to control, protect, or isolate equipment, usually for maintenance or to clear faults.

Switchgear

System Emergency NERC defines this as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.

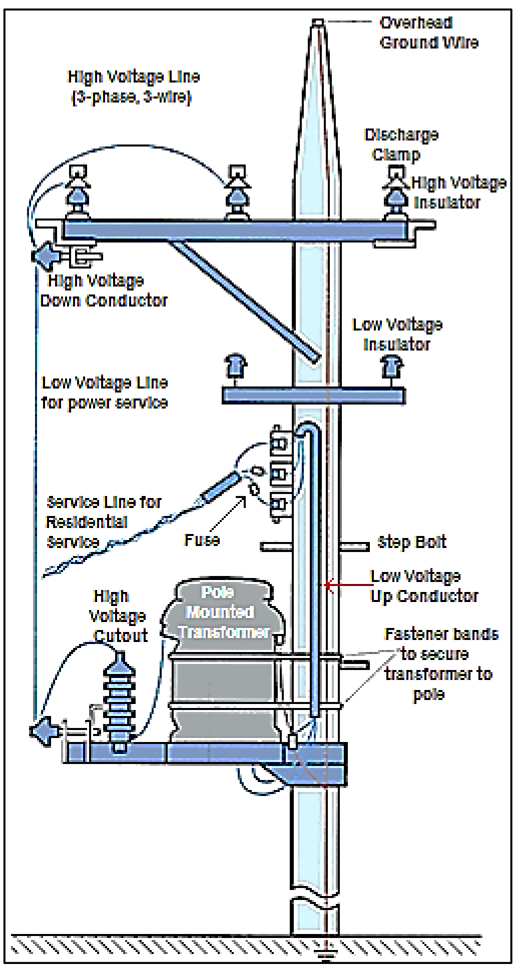
System Operating Limit Operating the elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits is required so that instability, uncontrolled separation (islanding), or cascading failures of the system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements. It is a limit put in place to prevent entering an unstable operating state (Emergency or Extreme).

Tap (or Tap Point) A tap is a segment of transmission that ties the line into a substation.

Three-Part Communication Protocol A communication protocol required by NERC for system operators where:

1. Information is verbally stated by an initiating party;
2. The receiving party repeats the information back correctly (not necessarily verbatim) to the initiating party; and then
3. The initiating party either confirms the information repeated by the receiving party is correct, or reinitiates the communication until the information repeated by the receiving party is confirmed to be correct.

Tie Line is a circuit connecting two Balancing Authority Areas (individual utilities) such as the tie between Idaho Power and Avista which allows them to share energy and reserves.



Time Error occurs when the synchronous interconnection operates at a frequency different than the interconnection's <u>scheduled</u> frequency, resulting in an imbalance between generation and loads/losses, and thus creating inadvertent interchange, when more energy passes through a system than has been agreed upon.

Time Error Correction is an offset to the interconnection's scheduled frequency to return the interconnection's time error to a predetermined and accurate value.

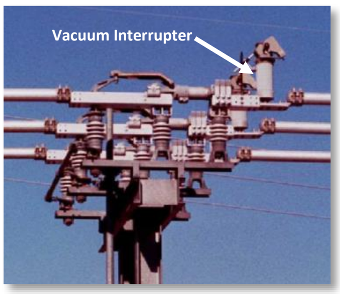
Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines or paths between those areas (under specific system conditions.

Transfer Capability This is the measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines or paths between those areas (under specific system conditions). The units of transfer capability are expressed in terms of electric power, generally in megawatts (MW). Note that the transfer capability from "Area A" to "Area B" is not always equal to the transfer capability from "Area B" to "Area A."

Transmission Constraint is the limitation on one or more transmission elements that may be reached during normal or contingency system operations.

Transmission Reliability Margin (TRM) is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the uncertainty in the transmission system and provides some flexibility in keeping the system operating smoothly when system conditions change due to line loss, generation loss, or unexpected weather.

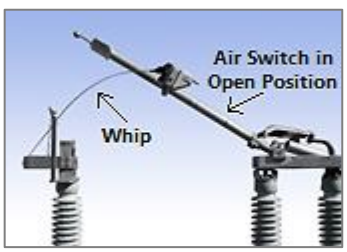
Trip and Reclose (T/R) Also called a breaker momentary, a trip and reclose occurs when a circuit breaker is able to clear a fault and quickly restore power by closing the circuit breaker to put the line back in service.



Vacuum Interrupter Air Switch This uses electrical contacts inside a vacuum inside a container to interrupt the circuit on a transmission line. When a circuit is broken, it creates an arc. In this type of device, the arc is contained inside the interrupter and is quickly extinguished.

Voltage regulator is hardware installed in a substation or out on the distribution circuit that adjusts to keep the voltage within acceptable limits during heavy and light loading periods. Sometimes used on long distribution feeders to keep the voltage up over great distances.


Voltage Regulators



Whip Type Air Switch is used to interrupt the circuit on a transmission line. An arc is drawn when a circuit is opened as a result of the capacitive charging current of the bus and the connected voltage transformers. The arc is quickly extinguished by the switch's arc whips.